A compendium of articles on the technical and financial benefits of steam efficiency, presented by stakeholders in the U.S. Department of Energy's BestPractices Steam efforts.

STEAM DIGEST 2002

Compiled for the

INDUSTRIAL TECHNOLOGIES PROGRAM

By the

ALLIANCE TO SAVE ENERGY

ALLIANCE TO SAVE ENERGY

Creating an Energy-Efficient World

U.S. Department of Energy

Energy Efficiency and Renewable Energy

Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

Acknowledgements

The *Steam Digest 2002* is the third annual compilation of articles dedicated to steam system efficiency. The U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy sponsors the BestPractices Steam program, which either directly or indirectly facilitated the creation of all the articles contained in this volume.

Since its inception, the BestPractices Steam program has been led by **Mr. Fred Hart** of DOE. **Dr. Anthony Wright** continues to direct the evolution of the program's technical content, notably including the development of software such as the Steam System Scoping Tool and the Steam System Assessment Tool. **Mr. Christopher Russell** of the Alliance to Save Energy conducts outreach on behalf of the program, making sure that program materials are properly distributed among state energy programs, utilities, trade associations, industry media, and the Internet. **Ms. Kristin Lohfeld** continues in this capacity as of March 2003. **Mr. Carlo LaPorta** of Future-Tec covers too many tasks to mention, and now is duly recognized.

Mr. Fred Fendt of Rohm & Haas now serves as Chair of the BestPractices Steam Steering Committee. **Ms. Debbie Bloom** of ONDEO-Nalco continues as Vice-Chair. These individuals participate on the BestPractices Steam Steering Committee:

Bob Bessette
Council of Industrial Boiler Owners
Victor Bogosian
National Board of Boiler and
Pressure Vessel Inspectors
Charles Cottrell
North American Insulation Manufacturers
Association
Beverly France
Industrial Interactions
Elodie Geoffroy-Michaels
Turbosteam
Robert Griffin
Enbridge Consumers Gas
Glen Hahn
Spirax Sarco
Bill Haman
Iowa Energy Center
Tom Henry
Armstrong Services, Inc.
Walter Johnson
Association of Energy Engineers
Michele Jones
National Insulation Association
Sandra Khalil
Consultant
Anthony Martocci
Bethlehem Steel
Jim Moore
TA Engineering
Christina Mudd
Maryland Energy Administration
Kelly Paffel
Plant Evaluations & Support
Miriam Pye
New York State Energy Research &
Development Authority
Doug Riley
Millennium Chemicals
Mike Sanders
Sunoco
Thomas Scheetz
BASF
John Todd
Yarway Corp.

We offer grateful recognition to each author for his or her contribution to this compendium. Special thanks go to **Ms. Sharon Sniffen** of ORC Macro for assisting with the publication of this volume.

TABLE OF CONTENTS

Introduction

Christopher Russell, Alliance to Save Energy
Fred Hart, U.S. Department of Energy
Dr. Anthony L. Wright, Oak Ridge National Laboratory

Why steam?

Steam—or more specifically the heat that steam provides—played a role in the production of virtually everything in the room around you. That includes the paper and ink in this document. It tempered the adhesives and fibers in wood-product desks and cabinets. Steam helped to manufacture your chair: plastics in the handles, foam cushioning in the seat, and the fabric covering as well as the pigments that color each of those items. Nuts, bolts, screws, and other metal fixtures were pre-heated with steam so that corrosion-retarding chemicals could be applied to them. The walls that surround you are probably made of either sheetrock or paneling, both of which were pressed from a steam-heated slurry of raw materials. Paints on your walls, pencils, and filing cabinets include polymers with a molecular structure that could only be assembled by high-temperature chemical reactions (again, facilitated by steam). The electric light by which you read was almost certainly produced by a steam turbine, fired by coal, natural gas, oil, or nuclear energy. And that bag of potato chips? The potatoes were "peeled" in a large, pressurized vat that accepted steam injection for 62 seconds, at which point the pressure was removed and the liquid content of the potatoes literally blew the skin off, leaving the potato whole.

That was only a short list of steam products.

Steam use in manufacturing can, and should, be part of any attempt by policy makers to address resource conservation, industrial competitiveness, energy market structure, and climate change. The following are facts that will substantiate[1] :

- Thirty-five percent of all fuel consumed by industry for energy purposes is devoted to raising steam.
- Fuels consumed by steam systems (industrial, commercial and institutional) are roughly nine quadrillion Btu, or about one tenth of national primary fuel demand for everything, including transportation.
- A one percent improvement in industrial energy efficiency—which is technically easy to accomplish—would return to energy markets a volume of fuel sufficient to satisfy the non-transportation energy needs of 3.2 million households.

BestPractices Steam is a U.S. DOE program that promotes steam efficiency. The program does not regulate or compel action on anyone's part. Instead, it simply identifies, documents, and communicates best-in-class steam management technologies and practices. These findings are made freely available in a series of reference documents, tip sheets, case studies, diagnostic software, and more—either printed or available for Internet download.

The articles in *Steam Digest 2002* represent a variety of operational, design, marketing, and program assessment observations. Readers are encouraged to also consult the 2000 and 2001 editions for additional reference. Please contact:

- U.S. DOE Office of Energy Efficiency & Renewable Energy Resource Room: (202) 586-2090;
- EERE Clearinghouse: clearinghouse@ee.doe.gov (800) 862-2086;
- http://www.oit.doe.gov/bestpractices/steam; or
- http://www.steamingahead.org.

[1] All data from U.S. DOE Energy Information Administration

Energy Efficiency and Industrial Boiler Efficiency: An Industry Perspective

Robert Bessette, Council of Industrial Boiler Owners

Energy efficiency for industrial boilers is a highly boiler-specific characteristic. No two boilers are alike. There are two identically designed, constructed side by side, stoker fired boilers in Indiana burning the same fuel that have very different performance characteristics. Like twin teenagers, they are not the same. Consideration of energy efficiency for industrial boilers, more often than not, is simplified and categorized to a one-size-fits-all approach. Just as when considering teenagers, this does not work. While parents would like to believe their teenager is gifted and talented and in the 80th percentile of the population, we know that is not necessarily the case. We also know, as for boilers, the average teenager is not representative of a widely diversified population. If you think it is, ask any parent with teenagers or an industrial boiler operator. While the variables associated with energy efficiency are more limited than those associated with a teenager, they are in no way any less complicated.

Four factors are critical for assessing energy efficiency in the industrial powerhouse supplying energy to make products for the benefit of customers in a highly competitive international marketplace. These are:

1. fuel type,
2. combustion system limitations,
3. equipment design, and
4. steam system operation requirements.

Furthermore, the industrial facility's complexity, location, and objective complicate them. It is important for the industrial company to remember, unlike the utility, that energy is a smaller portion of the final product price. However, without energy there is no final product or service. Needless to say, without products or services there is no need for people to do the work.

This white paper will address the efficiency-related aspects of the four primary factors affecting the industrial boiler and the factors affecting application of combined heat and power systems to industrial facilities. A copy of the *Background Paper on the Differences Between Industrial and Utility Boilers* is included as an appendix to help understand the diversity of the industrial boiler population. From the EPA Boiler MACT Database, there are about 22,000 industrial-commercial and institutional boilers with greater than ten million Btus per hour heat input.

New vs. Existing Units

Before investigating specifics of industrial boiler efficiency considerations, it is important to understand that once a boiler is designed, constructed, and installed, it can be difficult and costly to improve its efficiency above the design. On the other hand, as will be discussed below, changes in fuel, load, and operation can easily impact overall efficiency. Because of the high cost of the energy plant, boilers and associated systems usually are purchased for the life of a facility with ample margin for future growth and process variability. With proper maintenance, boiler life is indefinite. In most cases, it will outlive the process it originally was designed for but not the facility. For example, a facility that was producing eight track tapes changed to produce cassette tapes and is now producing CDs and DVDs. The boiler will still be there meeting new demands.

With today's technologies it is possible to design boilers to handle a wide range of requirements and possibilities. However, in most cases this is economically impossible if a process is to survive in a competitive world. It could be like building a new home with a heat pump and a furnace capable of burning natural gas and a furnace capable of burning oil to cover the heating, air conditioning, hot water, and other household needs. The cost of all of this equipment would break the budget. It is evident that an average person probably could afford only one of these devices. If the person tried to buy all three, they would not be able to afford the house.

New units are purchased with a guaranteed efficiency at a Maximum Continuous Rating (MCR) for a specific design fuel producing a specified quantity of steam or hot water at a specified temperature and pressure. Any changes in these characteristics change the operating efficiency. A guarantee over a wider range of fuel, capacity, and temperature and pressure is technically possible. However, as mentioned, it may not be economically justifiable for a given facility. In the end, a new unit may be defined only as one that is designed, purchased and installed, but never run at the guarantee conditions other than to pass acceptance tests. In the real world almost nothing operates at the design specifications.

Annual Average vs. MCR Design

If you start from cold water have you ever watched how long it takes to get it boiling? I believe it was Ben Franklin who said, "A watched pot never boils." It does, but it takes the addition of 1,000 Btu per pound of water before it does. After that, considering losses from the teapot or boiler, Btu for Btu, is converted to steam where you use it or lose it. In systems that have a heavy cyclic load, the operator can either start up or shut down the boiler as needed (for a period lasting 2 to 5 hours each way) without the loss of much of the initial energy. However, for periods longer than this, much if not all of the initial 1,000 Btus are lost. On the other hand, the operator can keep it at pressure to ensure rapid response by supplying enough heat to compensate for losses in the system. Here, efficiency is zero, but the initial 1,000 Btus are maintained. In both cases there is increased energy loss and the inability to meet or maintain MCR efficiency. In facilities like a college campus, with a heating load, where heat is needed every morning so the students will have warm classes to go to, hot showers to wake up with, and hot food in the cafeteria serving lines, it is better to keep the boiler hot, lose the efficiency, and keep the students, their professors and their parents happy. In a large hospital performing many major surgeries per day using autoclaves to sterilize surgical instruments, should a system be designed to handle the maximum number of surgeries expected or a smaller number thus limiting the number of people that can be helped in any one day? Obviously, the system must be designed to meet the maximum capacity of the hospital. Here it is impossible to deliver both MCR efficiency conditions and optimum patient service. There also are losses associated with low load operation that will be discussed in greater detail under the Systems Operation section below.

Each facility's needs will be different. Steam load requirements will change for different facilities. Departures from MCR conditions will vary widely depending upon facility process needs. Subsequently, the annual average efficiency, and for some, the hourly average efficiency will be less than the MCR efficiency of the design. Differences between actual efficiency, an annual average, and MCR can be as much as 40 percent or more depending upon the facility. Any consideration of industrial boiler efficiency must consider differences between real, actual, and design efficiencies.

The ability of a particular process to use steam efficiently complicates this factor. With steam after it is produced you use it or loose it. Inefficiencies inherent for various process factors can be as important as the inefficiencies associated with the boiler.

Fuel Type

Mother Nature is miraculous. Naturally occurring fuel (gas, oil, wood, coal and biomass) is variable. The plants, animals, bugs and other critters that formed the fuel underwent tremendous change at different locations and over different time periods. Elemental compositions of fuel [moisture (H_2O), carbon (C), hydrogen (H), nitrogen (N), chlorine (Cl), sulfur (S), oxygen (O) and ash] can vary as much as 30 percent or more from an annual average basis depending upon their inherent composition and degree of fuel refining or preparation. Any variations in fuel composition from the original design of the system will directly affect boiler efficiency. In most cases with boiler design these days, variations of less than one or two percent from the design fuel composition will have virtually no perceptible impact on efficiency. For this discussion, the Btu per pound, gallon, or cubic foot of the coal, oil, or gas respectively may be a better, however over simplified, way of looking at it.

Even natural gas can vary between 900 and 1,100 Btu/cu. ft. depending upon the methane content. Over the years technology has allowed gas companies to blend gas and control its Btu and composition to a level of around 1,000 Btu/cu. ft. (+ or – one or two percent) on an annual average and hourly average basis. This, along with its deliverability, ignitability and controllability is a good reason why natural gas is used as a primary fuel for home heating, hospitals and commercial installations. The very high hydrogen content (high hydrogen to carbon ratio) of natural gas that burns to form water removes a significant amount of heat from the process and can seriously impact the overall efficiency of the boiler as compared with other fuels.

Crude oil is refined to remove the highly valuable portion for industrial feedstocks for plastics and other products, for gasoline, aviation fuel and diesel fuel for transportation, and for home heating oil with very low variability. The variability of each of these premium products can be equal to or better than that of natural gas. Industrial fuel products are the leftovers from refining and can have increasing variability as the quality goes from a No. 2 oil to a No. 6 or high asphaltene Bunker C grade oil or road grade asphalt or petroleum coke. In such cases, variation in viscosity (burning something like "black strap molasses" or hot maple syrup for the liquids – coke is a solid more like coal) can have a serious impact on combustion efficiency and overall boiler efficiency. Variation in fuel characteristics on an hourly average basis may be better or equal to that of natural gas. However, variations in fuel characteristics between shipments over the year may increase the annual average variation to somewhere in the range of five percent. Because oil has a lower hydrogen content (decreasing with increasing grade) than natural gas, the overall boiler efficiency associated with burning fuel oils usually is higher both at MCR and annual average. Oils are very good boiler fuels.

Coal, our most abundant fuel, can be mined with new technologies and coal preparation plants to remove rock (contaminants) captured in the process to a plus or minus 10 percent natural variability within a given seam. However, different coal seams vary tremendously from lignite at 4,000 Btu per pound with seven percent hydrogen and 35 percent moisture to anthracite with 14,000 Btu per pound with two percent hydrogen and three percent moisture. With low hydrogen contents (low hydrogen to carbon ratio), coal is the most efficient energy source for conversion of Btus into usable energy.

Blends of various coal seams and the inability to remove contaminants, if there is no preparation plant, can lead to fuel quality variations of 10 percent or more on an hourly basis and 20 to 30 percent on an annual basis. Coal fired systems normally are designed to handle up to a plus or minus 10 percent variability without visible degradation of performance. Because of the diversity of coal types, locations, and characteristics, different types of combustion systems are used to burn fuel and generate energy. The following sections will look at this aspect in more detail.

Wood and biomass are solid fuels with both high hydrogen to carbon and high moisture content (greater than 40 percent). Because of energy loss due to moisture from the combustion of hydrogen and conversion of moisture to vapor (1,000 Btu per pound), it is very difficult to obtain efficiencies, either MCR or annual average, equal to or approaching those of natural gas, never mind oil or coal. A very good annual average efficiency for a wood or biomass unit may be in the 60 percent range. While fuel property variations may be better than coal, these variations usually occur in the moisture content with a direct and major impact on boiler efficiency.

Fuel characteristics determine the design of a particular unit. Fuel changes, especially in hydrogen and moisture content outside the range of one or two percent for natural gas, three to five percent for oil and 10 percent for coal and other solid fuels, will have an impact on efficiency, both MCR and annual average. When fuels are switched, the interaction of the new fuel and the boiler often produces negative impacts on either the load or the boiler efficiency. These effects often are amplified because of limitations encountered in specific areas of the boiler where these adverse interactions occur. A good analogy would be a truck that comes onto a superhighway that has bridge clearances more suitable for cars. When the truck approaches a bridge, it has to slow down to ensure that it can pass under a place where the clearance is adequate. This causes traffic to move slower because the highway was not designed with the truck in mind.

Combustion Systems

Efficient fuel burning (combustion) requires attention to the entire combustion apparatus. Because some problem areas are common to all types of combustion systems, those areas will be discussed before reviewing specific system problems.

Good combustion is the ability to mix air and fuel, with as little excess air as possible, at a high enough temperature to sustain the process and completely burn the fuel (complete carbon conversion) with minimum environmental emissions. Good combustion also includes the ability to generate maximum usable energy consistent with process needs, safety, and economics. This is a complex process of matching fuel combustion characteristics, ignition, including pyrolysis, and char burn out for heavy liquid and solid fuels, with the time, temperature and turbulence available from the furnace absorption profile and combustion system capabilities design. All this has to be accomplished with the safety of operators and facility personnel in mind.

Each year, the news media inform us of boiler explosions that kill people – be it a steam tractor at a county fair or an industrial or utility powerhouse in the center of a city. A typical 100,000 pounds per hour steam boiler requires about 125 million Btus (MMBtu) of fuel input each hour. That is equivalent to approximately 1,100 gallons of gasoline, 125,000 cu. ft. of natural gas, and a little more than 900 gallons of kerosene. What we have is a controlled explosion where we take energy out and use it for beneficial purposes. There can be problems with this. Safety must always be our number one priority.

Combustion systems, while they may seem simple, are very complex. Included in Appendix B is Chapter 3, "Combustion," of the CIBO Energy Efficiency Handbook. Here additional details of day to day concerns for optimizing and maintaining combustion efficiency are presented.

Equipment Design

Industrial boiler equipment is as varied as the products and processes it serves. A better understanding of this is given in Appendix A, "Differences Between Industrial and Utility Boilers." Boilers are one means of extracting energy from controlled fuel combustion. There are watertube, firetube, field-erected, and packaged shop-assembled units from very small to very large. The concept is simple, like a teapot. Boil water to make steam. However, the actual process is complex. Turning 100,000 pounds of water (that's 12,500 gallons, 1,250 fish tanks or a swimming pool) to steam each hour brings with it many complications.

It is impossible to capture each and every Btu from combustion in the boiler. For example, some get away to the atmosphere. Industry has devised ways to capture most of the Btu's economically. As an old farmer might say, they capture everything but the squeal. Of course, today it could be possible to capture that on a CD if it had a use. It is not done and probably will not be done because it would cost more to buy a CD recorder and take more energy to run the CD recorder than the value of the squeal. The same thing happens with energy. Some of it gets away and that varies with the boiler, the fuel, and the plant requirements. If it can be used cost effectively, it is.

A discussion of some of these losses is included in Appendix C, Chapter 4: "Boilers" of the CIBO Energy Efficiency Handbook.

System Operations

The ideal situation would be to be able to operate the boiler or energy device at the design MCR. If everything were perfect, one could design a unit that would have a relatively flat efficiency curve across the load range. A tangentially fired boiler with tilting burners could adjust tilts to achieve the same exit gas temperature with the same level of excess air and the same combustion efficiency at all operating loads (**the three main determinants of boiler efficiency**). However, this type unit is used primarily in the utility industry on larger boilers.

CIBO's Energy Efficiency Handbook points out (at the bottom left of page 26 in Chapter 5, "Controls" under Oxygen Loop), that most burners require more excess air at low loads than at high because there is less effective fuel to air mixing. This is due to mixing characteristics of flow streams and the fact that less total reacting gas is now filling the furnace volume. Air infiltration aggravates this condition because infiltrated air does not mix with the fuel at all. These factors cause mixing problems and also lower the bulk flame temperature, which, in turn, slows down combustion reactions. As a result, the higher excess air at lower loads causes a decrease in boiler efficiency due to the additional air that must be warmed up to stack temperature and exhausted to the atmosphere. For natural gas firing, this impact is not too bad. An estimate of a five percent efficiency drop from full load to 25 percent load probably is reasonable for a modern, tight, package boiler with full combustion controls. On the other hand, an old stoker with no air controls leaves the airflow fixed and drops load by reducing fuel input. In such cases there could be more than 200 percent excess air at low loads causing boiler efficiency to drop from about 85 percent at high load to around 60 percent at low load.

The problem with generalizations is that there are so many factors including fuel type, as-received condition of the fuel, boiler type, control system, amount of air leakage, maintenance status of the unit, and more. Larger units tend to suffer less than smaller units because they have multiple burner sets that can be turned off completely at low loads leaving remaining burners to run as if they were at full load. Also, larger units tend to be newer and have better control systems to adjust the operation thus reducing losses in efficiency associated with lower loads.

At the risk of oversimplifying the problem, if we assume a relatively new unit, firing coal, oil, or gas we can use the following ranges:

Table 1: Typical Efficiency For New Boilers

Coal	Full load efficiency - 85%	Low load efficiency - 75%
Oil	Full load efficiency - 80%	Low load efficiency - 72%
Gas	Full load efficiency - 75%	Low load efficiency - 70%
Biomass	Full load efficiency - 70%	Low load efficiency - 60%

It is sufficient to say that under normal operation, efficiency is lower than guaranteed efficiency of the new unit operating at MCR. However, for comparative reasons, design modifications or operational and fuel changes that impact MCR efficiency should have a proportional impact on actual efficiency the facility is achieving on an annual average basis.

Combined Heat and Power

Ideally, energy is used most efficiently when fuel is combusted at a high temperature and high temperature Btus are converted to electricity or mechanical energy in a gas turbine, internal combustion engine, or back pressure steam turbine followed by the use of the lower temperature Btus to meet process needs through heat transfer.

Electricity, mechanical energy, and heat are different forms of energy. Scientists have shown that different forms of energy have different qualities based upon the ability to perform useful work. Scientists tell us that electricity and mechanical energy produce work more effectively than heat energy. In other words, a Btu worth of electrical or mechanical energy has more value than a Btu worth of heat energy (similar to money where a U.S. dollar is worth more than a Canadian dollar). Furthermore, a higher temperature Btu has more value than a lower temperature Btu because it can be converted more efficiently into more valuable electrical and mechanical energy. However, both electrical and mechanical energy must be produced from some other energy source.

Starting with fuels, industry accomplishes conversion by burning the fuel and releasing heat. An engine then converts heat energy into mechanical or electrical energy. If combustion occurs inside an engine, it converts heat energy to mechanical energy that can be used to drive a pump, fan, compressor, or electrical generator. Exhaust leaving the engine is hot. This exhaust contains over half of the Btus released during initial combustion of the fuel and it can exceed 1,000 °F. If none of the exhaust heat is used, the device is known as a simple cycle. If heat is recovered from the exhaust for the additional utilization, the combination of the engine and other devices is known as a cogeneration system or a combined cycle system.

Efficiencies for simple cycles vary depending upon the design, size, and location of the engine (gas turbine, internal combustion engine). This also translates into a range of efficiencies for combined cycles. As with boiler efficiencies one size does not fit all. Example efficiencies for conversion to electricity in simple and combined cycles are as follows:

Typical Electric Generation Efficiencies		
Simple Cycle Applications	Low Range	High Range
Gas Turbines	25% Net HHV	About 38% Net HHV
ICE Engines	20% Net HHV	41% Net HHV
Coal Boilers / Steam Turbines	25% Net HHV	About 40% Net HHV
Wood Boilers / Steam Turbines	15% Net HHV	25% Net HHV
Combined Cycle Application		
Gas Turbines / HRSG Steam Turbine	40% Net HHV	57% Net HHV

HHV = 1

An examination of the electricity generation efficiency table shows that when electricity is the only product, maximum Btus recovered are about 40 percent for simple cycles and 54 percent for combined cycles. The increased efficiency for the combined cycle shows that only about 25 percent of the exhaust heat can be converted to electricity with modern technology. The difference between 40 percent conversion for the simple cycle and 25 percent additional conversion illustrates the difference in value between low temperature heat and high temperature heat.

The concept of combined heat and power provides further efficiency improvements over producing only electricity using exhaust heat directly in the manufacturing process. Many manufacturing processes require heat at temperatures between 250°F and 700°F. The Btus provided by the exhaust from the above applications are at temperatures that match these temperature requirements well. Hence, by converting high temperature, high quality Btus to mechanical or electrical energy and taking the lower temperature, lower quality Btus to meet process temperature needs, the energy in fuel can be used most effectively and efficiently. With this combination, from 60 percent to 85 percent of the Btus in the fuel can be recovered and used effectively.

After comparing these efficiencies with boiler efficiencies listed in Table 1, on the surface nothing seems to have been gained. However, the gain comes when one considers that for electricity generated at a central plant or for mechanical energy to run a compressor, fan, or pump, from 60 percent to 75 percent of the Btus are lost. Under a conventional system, a boiler or other combustion device is still required to provide heat for the facility or manufacturing process. For those that may want a more technical discussion of combined heat and power and efficiency, the following should help provide additional insight.

Combined Heat and Power Efficiency

The most common expression of efficiency is a comparison of the desired output of a process to the input. Electrical power generation efficiency is a relatively simple concept because electrical power is the only desired output and fuel energy is the only input.

Equation 1:

Efficiency = $\eta_{\text{electrical generation}}$ = η
Electrical Power Produced / Fuel Energy Input =
Energy Desired / Purchased Energy

A very common type of electrical generation system consists of a boiler and a steam turbine arrangement. In this arrangement the boiler serves to input fuel energy into water to produce steam. The steam exits the boiler with a very high energy content. As an example, the boiler may add 1,450 Btu of fuel energy to every pound of water passing through the component. The steam turbine serves to convert this thermal steam energy into mechanical or shaft energy. The turbine is very effective at this conversion process; in fact, nearly 100 percent of the steam energy extracted by the turbine is converted into shaft energy. However, this excellent efficiency only applies to the thermal energy extracted by the turbine. The turbine actually leaves the vast majority of thermal energy in the exhaust steam. As an example, a steam turbine may extract 450 Btus of thermal energy for every pound of steam passing through the turbine. This energy is readily converted into electrical energy with excellent efficiency, nearly 100 percent. However, recall the boiler input 1,450 Btus of thermal energy into every pound of steam. Therefore, 1,000 Btus remain in each pound of steam exiting the turbine. This steam exiting the turbine is not useful to the power generation system and is discarded from the system. The steam energy is discarded by cooling or condensing the steam. This gives rise to the description of this system as a “condensing turbine” system. The desired output of this system is the 450 Btus of electrical energy and the input is the fuel-input energy (1,450 Btus of fuel energy). The efficiency of this system would be as follows.

Equation 2:

$\eta_{\text{electrical generation}}$ = 450 Btu / 1,450 Btu = 31%

Industrial systems utilizing combined heat and power arrangements have a need for the thermal energy discharged from the turbine. This provides the basis for the advantage of combining heat and power generation systems. If the 1,000 Btus in every pound of steam can be used in a productive manner the fuel utilization efficiency can dramatically increase. In a combined heat and power system there are two desired products, electricity and thermal energy. The fuel utilization efficiency equation will take the following form.

Equation 3:

η_{CHP} = Electrical Power Produced +
Useful Thermal Energy / Fuel Energy Input

In theory, this efficiency could reach 100 percent, in reality, inefficiencies result in maximum efficiencies approaching 70 percent. Note that this efficiency considers thermal energy equal in value to power. This may not be the case because power is normally more valuable (easily usable) than thermal energy, but thermal energy is valuable. Some common examples where steam could be more valuable than electricity are sterilizing hospital instruments, making paper and steam tracing chemical lines. Other mechanisms are utilized to produce electrical power; however, current conventional mechanisms consuming fuel (combustion turbines and reciprocating internal combustion engines) result in very similar arrangements.

Condensing steam turbines with the ability to condense unneeded steam are often incorporated into industrial combined heat and power systems to allow the system to be balanced. In other words, if the demand for thermal energy diminishes and the demand for electrical energy increases, steam can be passed through a condensing steam turbine to produce the additional power while maintaining a more uniform and efficient load and without venting the steam. The fuel energy utilization efficiency of operating the condensing turbine returns to the low value described above (31 percent and even much less) for that portion of the steam condensed. In order for condensing power to be cost effective, the fuel cost must be significantly less than the electricity cost. In fact, because the industrial facility will generate condensing power less efficiently than the large utility, in the evaluation, to produce electricity through condensing, efficiency losses must balance against process needs, availability requirements, and alternative electricity purchasing costs or sales revenues.

Example:
Consider an industrial facility requiring both thermal energy and electricity. The facility currently purchases electricity from the local power generator and fuel from the fuel supplier. The local power generator purchases fuel from the same fuel supplier as the industrial customer. The local power generator purchases 100 units of fuel and converts this into 31 units of electrical energy. This electrical energy is consumed in the industrial facility. The industrial facility purchases 100 units of fuel and converts it into 80 units of thermal energy. A combined heat and power system could be operated at the industrial complex to supply the same amount of electrical and thermal energy. The combined heat and power system might require 143 units of fuel energy to supply the same thermal and electrical demands as the 200 units of fuel originally required. This is a 28 percent reduction in fuel consumption.

To give you an idea of relative cost, comparison of the use of natural gas and electricity for home heating may be beneficial. Assuming the same amount of energy is needed to keep the home warm on a very cold day (some temperature less than freezing outside), a simple calculation can help understand the differences. We can look at the energy costs in dollars per MMBtu delivered. Natural gas is normally sold in cents per therm (100,000 Btu). Multiply this by 10 and we have $/MMBtu.

For natural gas, if you pay 62 cents per therm, you pay $0.62/therm x 10 therm/MMBtu = $6.20/MMBtu.

Electricity is normally sold in cents per Kilowatt (kW). Multiply this as dollars by 293 kW/MMBtu gives dollars per MMBtu, something that is directly comparable to the cost of other energy sources.

For electricity, if you pay 10 cents per kW, you pay $0.10/kW x 293 kW/MMBtu = $29.30/MMBtu.

Thank goodness for heat pumps when the temperature is in the proper range. Here they are about 300 percent efficient and that lowers the heating cost to about $9.80 per MMBtu.

Application of Combined Heat and Power Systems

The discussion above explained advantages of combined heat and power systems using gas turbines, internal combustion (IC) engines, combined with boilers to show how these systems use Btus released from fuel combustion more efficiently. A common combined heat and power system (perhaps the oldest for industrial applications) consists of generating high temperature, high-pressure steam and running it through a back pressure steam turbine to produce electricity. Hot exhaust from the turbine goes to the process to use the lower temperature Btus. This section covers applications of various combined heat and power systems to show that selection of the optimum system depends upon the resources and needs of the facility.

The main factors that determine the type of energy supply system for a given facility are:

- Fuel availability;
- Proportion of plant energy needed in the form of electrical, mechanical and heat;
- Extent and frequency in supply requirements for steam; and
- Market for surplus electricity.

Fuel availability

Fuel availability depends upon the geographical location of the facility, products produced, cost of various fuels, and compatibility of various fuels with plant processes. Some example industries that demonstrate this relationship are: pulp and paper, cane sugar processing, refineries, ammonia plants, and batch chemical plants. Contrary to popular opinion, there are areas in this country where natural gas is not available but where there are abundant supplies of coal or other fuels.

Pulp and paper and cane sugar processing are examples of industries that produce a fuel byproduct used for some or all of their energy supply. The pulp and paper industry burns bark and wood from trees that provide feedstock for making pulp and paper. It also burns pulp residue that otherwise would be wasted. The sugar industry burns bagasse, which is leftover material after sugar has been squeezed out of sugar cane. These fuels are solid biomass. The paper industry supplements fuels with coal, another solid fuel that is burned easily with biomass. Other biomass fuels include palm fronds, peanut shells, rice hulls, hog manure, and poultry litter. If it has Btu value, someone can use it, and probably is using it for a fuel to generate valuable energy and eliminating a potentially serious waste disposal problem.

Refineries process crude oil, and use fuel byproducts (gas, heavy oil, and coke) for most of their energy requirements. These fuels are supplemented with small quantities of natural gas.

Ammonia plants use natural gas with some of their byproduct purge gas. Natural gas is both a fuel and the feedstock.

Batch chemical plants use a variety of fuels (natural gas, oil and coal) mainly depending upon the geographical location of the plant.

Need for electrical, mechanical, and heat energy

The proportion of energy in the forms of electricity, mechanical energy, and heat energy is important in determining the extent to which a combined heat and power system can be applied at a given facility. When there is little need for electrical or mechanical energy, a combined heat and power system may not be practical. Using the industrial examples, the following observations are pertinent. If there is no need for thermal (heat) or mechanical energy at a location, there is no possibility for a combined heat and power system.

The pulp and paper industry needs heat in the form of steam to operate digesters that make pulp and to provide heat for drying paper. The industry needs electrical energy to run paper machines and mechanical or electrical energy to run debarking machines, pumps, and compressors. Due to these requirements, a pulp and paper mill often uses combined heat and power. Steam from boilers goes through backpressure turbines to make electricity; then exhaust steam goes to digesters and paper dryers to provide process heat.

Due to fuel availability and steam and electric process requirements, use of gas turbines is not normally practical in a combined heat and power application in this industry where energy efficiency maximization is of prime importance. Because the fuels contain high moisture levels, the thermal efficiency of the combined heat and power system within these facilities is inherently lower than in other applications.

Refineries require both electricity and heat energy. Recently, many refineries have added gas turbines with heat recovery steam generators (waste heat boilers). Electricity runs pumps, fans, and compressors inside the refinery, and steam from the waste heat boilers provide heat for refinery operations such as distillation units, reboilers, and other machinery that demand electricity and steam. Surplus electricity not used within the plant is sold to the electrical power grid. With available fuels, the combined heat and power system can attain very high efficiencies for refinery applications.

Another form of cogeneration involves the use of petroleum coke that is burned in a circulating fluidized bed boiler to generate steam. Steam goes to a backpressure turbine to make electricity and exhaust steam goes to the refinery to provide heat for refinery operations.

When discussing combined heat and power regulators, plant managers often concentrate on electricity generation followed by the use of the residual heat to produce steam. Although this is a typical combined heat and power scenario, it is not always the most efficient or effective use of technology at a given facility. For example, ammonia plants require a lot of mechanical energy to compress gases to very high pressure. For this case, it is better to use a gas turbine to drive the compressor(s) rather than use a large electric motor. The exhaust from the gas turbine contains high levels of oxygen as well as high temperature. This exhaust can be used to fire more fuel in a furnace that produces hydrogen for the ammonia process. In this case, the "power" is mechanical energy and the residual heat is converted directly to chemical energy and steam in the furnace. Due to process requirements it is not wise to make electricity with the gas turbine and send it to an electric motor to drive the compressor.

Batch chemical plants have varying needs for electricity, mechanical energy, and heat depending upon the product produced. The suitability and selection of various combined power and heat and power systems may vary widely depending upon process needs.

Extent and frequency in supply requirements for steam

Combined heat and power systems are less likely to be practical in small plants where steam requirements change rapidly. Many batch chemical plants have this characteristic. It is counterproductive to run a gas turbine or IC engine to produce electricity and to throw Btus into the atmosphere in the form of vented surplus steam.

Market for surplus electricity

In some cases, the need for electricity or heat is out of balance. Electricity must be generated in surplus quantities to produce enough steam for process use. In these cases, electricity must be salable at a price that exceeds the money needed to build the combined heat and power unit at the facility. Industry operates at low profit margins and cannot afford to give free electricity to other users. However, there is one thing for certain, if there is a need for steam there is a possibility for combined heat and power.

Internal Combustion Engines and Turbine Considerations With Waste Heat Boilers or Heat Recovery Steam Generators

Modern internal combustion (IC) engines used to generate electricity with either fired or unfired heat recovery boilers maintain their simple cycle efficiency, which is the highest efficiency of commercial technologies under real-world ambient temperatures and elevations above sea level. Cogeneration applications that recover the maximum amount of waste heat created by the generation of the electrical component of the plant achieve overall efficiencies in excess of 80 percent on a high heating value (HHV) basis. Simple cycle thermal efficiencies can exceed 41 percent on a HHV basis, i.e., those when only electricity is being generated and no waste heat recovery is occurring.

Cogeneration applications favor gas turbine technology when the process requires a massive amount of high temperature steam. Gas turbines create large quantities of high temperature exhaust gas, resulting in the need to generate large quantities of high temperature steam in order to achieve acceptable overall plant thermal efficiencies. If uses for the large quantity of high quality steam are available, then gas turbine technology usually is used.

In the other on-site situations requiring smaller amounts of steam and higher quantities of process hot water, modern IC engine technology provides the best economic returns for the owner and is the technology of choice.

As discussed previously, the reason that gas and oil have lower boiler efficiencies than coal is because these fuels have progressively higher hydrogen contents that generate water during combustion. This water is boiled and heated up to stack temperature where it is emitted into the atmosphere. (The water in this instance is formed as a vapor, as it contains the latent heat but does not pass through the boiling process in the combustion process). That moisture loss takes heat away from the energy available to boil the water inside the tubes to make steam for productive use. If there is moisture present with the fuel, such as surface water or humidity, that water also is lost to the stack and causes an efficiency loss. (Yes, the efficiency varies with the time of year and the weather.) Recognizing this loss, boilers are rated based on a higher heating value of the fuel. This efficiency includes unrecovered heat from allowing water vapor to exit the boiler.

Gas turbine advocates attempt to avoid this complexity by referring to the lower heating value of the fuel and doing all of their calculations at ISO conditions (59°F and one bar and constant relative humidity). In the real world, gas turbines lose efficiency faster than steam turbines as load is decreased, and lose output particularly fast as ambient temperatures and altitudes increase. Efficiencies presented in this white paper are all based on the higher heating value to provide adequate comparisons.

Summary and Conclusions

Owners and operators of industrial facilities strive to operate at optimum efficiencies. However, unlike the utility industry that produces a single product, industrial facilities are more complex. Boilers designed for such facilities are much more diversified in order to meet widely differing requirements. These different requirements naturally create optimal efficiencies that vary widely from industry to industry and from facility to facility. The one-size-fits-all approach often used by regulators to encourage increased energy efficiency simply does not work because this approach does not consider the many specific factors that affect energy efficiency.

This white paper has discussed major factors that significantly affect achievable energy efficiencies within various industrial facilities. Fuel type and availability, combustion system limitations, equipment design, steam system operation requirements, energy requirement mix, and outside market forces all affect the achievable efficiency of an industrial facility.

Fuel type and availability has a major effect. Fuels with high heating values, high carbon to hydrogen ratios, and low moisture content can yield efficiencies up to 25 percent higher than fuels that have low heating values, low carbon to hydrogen ratios, and high moisture contents. A rule of thumb for the efficiency hierarchy in descending order is coal, heavy fuel oil, light fuel oil, natural gas, and biomass. From these rankings, it is obvious that fuel availability plays a major role.

Factors such as combustion system limitations and equipment design limit the types of fuels that reasonably can be used within a given boiler. Because the design of older boilers is fixed, switching fuels often leads to significant losses in efficiency or capacity. In some cases changing from one fuel to another, such as natural gas to fuel oil, may improve efficiency.

Steam system requirements often have significant adverse impacts on achievable efficiencies especially for potential combined heat and power applications. Widely different steam demands can lead to periods where the boiler is kept running on “idle” in certain industries. Because the boiler produces little or no steam under these conditions, its operating efficiency is close to zero. The alternative of shutting the boiler down to conserve energy in fact wastes energy and often is not practical.

When possible, the application of combined heat and power produces large improvements in efficient energy usage. Use of high temperature energy to produce electrical or mechanical energy followed by the use of remaining lower temperature energy to meet process heat requirements is the ideal. Industries such as the paper industry have utilized combined heat and power for more than a half century. The highest efficiencies are achieved by systems combining IC engines or gas turbines with boilers or process heaters. However, these systems are not suitable for every facility. Factors such as fuel availability, the facility’s relative needs for electrical, mechanical, and heat energy, steam demand and demand cycles and the market for surplus power have major effects on whether or how combined heat and power may be applied at a given facility. Even where combined heat and power is applied, one size does not fit all, and various applications can have widely different efficiencies.

Appendix A

Differences Between Industrial and Utility Boilers

Industrial and utility boilers are significantly different. Yet, because both generate steam, legislators and requlators tend to treat them the same.

Major differences between industrial and utility boilers are in three principal areas:

➢ boiler size
➢ boiler steam application
➢ boiler design

Size

The average new industrial boiler is a dwarf compared to the giant utility boiler. Today's typical utility unit produces 3,500,000 pounds of steam an hour; the industrial boiler 100,000. In fact, most industrial boilers range in size from 10,000 to 1,200,000 pounds of steam per hour.

The size of the utility boiler allows it to enjoy significant economies of scale, especially in the control of emissions that simply are not available to the industrial unit.

Smaller industrial boilers are more numerous and tailored to meet the unique needs and constraints of widely varying industrial processes. There are about 70,000 industrial boilers in use today compared to approximately 4,000 utility boilers. Yet, all the small industrial units combined produce only a fraction of the steam compared with large utility boilers. In addition, the nation's utility boilers consume over 10 timeOs as much coal as the industrial boilers.

Industrial units produce less than 10 percent of the emissions from the nation's boiler population, but because of their smaller size and uniqueness must pay more than utilities to remove a given amount of emissions.

Steam Application

A utility boiler has one purpose—to generate steam at a constant rate to power turbines that produce electricity. Industrial boilers, on the other hand, have markedly different purposes in different industries. Even at a single installation, application of steam from an industrial boiler can change dramatically with the seasons, when steam or hot water is used for heating, as well as from day to day and hour to hour, depending upon industrial activities and processes underway at a given moment and their demand for steam. The possibility of such widely fluctuating demand for steam in most industrial processes means that the industrial boiler does not, in the great majority of cases, operate steadily at maximum capacity. In general, the industrial boiler will have a much lower annual operating load or capacity factor than a typical utility boiler. As a result, any added control costs have a much greater affect on the final output steam cost.

In contrast, a typical utility boiler, because of a constant demand for steam, operates continuously at a steady-state rate close to maximum capacity. This basic difference in operation is reflected in proportionately lower operating costs than is the case for similarly equipped industrial boilers. Even when peaking units operate to meet utility load swings during the days or for seasonal peak demands, the utility units' load swings are more controlled and can be balanced over the complete electric production and distribution grid.

In the event of unscheduled downtime for a given unit, utility electrical generating facilities have a variety of backup alternatives. Industry, on the other hand, rarely has a backup system for steam generation. Because of the desire to keep costs for steam production as low as possible, industry requires a high level of reliability from its boilers. Industrial boilers routinely operate with reliability factors of 98 percent. Any drop in reliability for an industrial system causes loss in production and related revenues. Combustion and add-on control technologies can interfere with system reliability.

Design

Utility boilers primarily are large field erected pulverized coal, No. 6 oil or natural gas fired high pressure high temperature boilers with relatively uniform design and similar fuel combustion technologies. Industrial boilers, on the other hand, incorporate combustion systems including high pressure and low pressure, large and small, field erected and shop assembled package boilers designed to burn just about anything that can be burned alone or along with conventional fuels. Industrial boilers use many different types of combustion systems. Some of these different designs include many different types of stokers, bubbling and circulating fluidized bed combustion systems, and conventional coal, oil and gas combustion systems. In fact, the designs of individual industrial boilers regardless of fuel or combustion type can vary greatly, depending upon application of steam and space limitations in a particular plant. On the other hand, facilities at a utility plant are designed around the boilers and turbine(s) making application of emission controls significantly more cost effective.

Conclusion

Differences between industrial and utility boilers are major. These differences warrant separate development of laws and regulations that apply to each. Treating them both in the same fashion, simply because they both generate steam, inevitably results in unfair and inappropriate standards.

Accordingly, the Council of Industrial Boiler Owners believes that government should recognize the basic differences between industrial and utility boilers and should tailor requirements to their individual natures and to the unique situations within which each operates.

Council of Industrial Boiler Owners

The Council of Industrial Boiler Owners (CIBO) is a broad-based association of industrial boiler owners, architect-engineers, related equipment manufacturers, and university affiliates consisting of over 100 members representing 20 major industrial sectors. CIBO members have facilities located in every region and state of the country; and, have a representative distribution of almost every type boiler and fuel combination currently in operation. CIBO was formed in 1978 to promote the exchange of information within industry and between industry and government relating to energy and environmental equipment, technology, operations, policies, laws and regulations affecting industrial boilers. Since its formation, CIBO has taken an active interest and been very successful in the development of technically sound, reasonable, cost-effective energy and environmental regulations for industrial boilers.

Decision Climate for Steam Efficiency: Update December 31, 2002

Carlo La Porta, Future-Tec

Abstract

The Performance Evaluation and Policy Subcommittee of the BestPractices Steam Steering Committee issues a periodic compilation of data that the Energy Information Administration, U.S. Department of Energy, reports in its Short-Term Energy Outlook. The author selected data relevant to industrial decision makers concerned with supply and price of energy purchased for industrial fuel. The ulterior purpose is to help frame decisions that will encourage more investment to improve the efficiency of industrial steam systems.

Data From U.S. Department of Energy Short-Term Energy Outlook

Weather Impacts

Despite an 11 percent increase in cooling degree days during summer 2002, high utility demand for fuel to make electricity did not create a spike in natural gas prices. Natural gas spot prices did, however, exceed $3.00 per thousand cubic feet in August and rose to $3.90 in November. Population-weighted heating degree days for October and November were 16 percent higher compared to normal in the Northeast United States and were eight percent higher than normal nationally. The winter after January is projected to be warmer than normal. A 12 percent colder winter of 2002-2003 will increase demand for heating oil, gas and electricity, and hold or pressure fuel prices upward and EIA has predicted that natural gas will be $1.50 more per 1,000 cubic feet than last winter.

Industrial Production

U.S. GDP is projected to be 2.3 percent higher in 2002 compared to 2001 and grow 2.6 percent in 2003. Manufacturing production fell in 2001 by 4.3 percent, was projected to fall another 0.4 percent in 2002, then rise 3.4 percent in 2003. U.S. business inventory dropped $36.2 billion ($1996) in 2001, and another $14.8 billion ($1996) is the projected drop for 2002. A gain of $6.7 billion is forecast for 2003.

Petroleum

The benchmark West Texas Intermediate oil spot price rose by $1.40 per barrel in August compared to July, averaging $28.40 per barrel (bbl) for the month. At that time OPEC was producing 1.8 million barrels per day over its quota and the October average price for OPEC oil was $27.60 per barrel. Iraqi production had fallen by 1.2 million barrels per day in August compared to August 2001. A political crisis in Venezuela cut its oil exports severely in December, which increased market uncertainty and put more upward pressure on oil prices. These conditions pushed oil prices above $30 per barrel by the end of 2002. The New York Mercantile Exchange price on December 31, 2002, for light sweet crude deliveries in February 2003 was $31.37/bbl. The February delivery price actually had dropped $1.35 per barrel based on news that an OPEC country had indicated OPEC production might increase to bring prices down. The EIA forecast has assumed that OPEC will increase production to keep the price in its desired range between $22-$28/bbl. Economists are concerned about continued slow recovery in U.S. economic growth and EIA has dropped its U.S. GDP growth rate projection from 4.1percent in 2003 to 3.0 percent. Still, EIA expects U.S. demand for petroleum products to rise 3.9 percent in 2003.

Table 1: World Oil Demand Growth (*italics signify forecast*)

Actual	Projected	
2001	*2002*	*2003*
0.0%	*0.4%*	*1.8%*

All data: U.S. DOE-EIA

In 2002, average daily U.S. oil production will have fallen one tenth of one percent (0.10 %) to 5.8 million barrels per day. In 2003 domestic production is projected to fall by 3.5percent to a level of 5.6 million barrels per day. With oil imports projected to average 10.5 million barrels per day in 2002, the U.S. will have depended on foreign oil for 64.4 percent of its supply.

Distillate Fuel Oil

Last winter, due to mild weather, the industrial downturn and expanded reliance on natural gas, distillate demand fell 230,000 barrels per day, or six percent, and inventories rose. By late November 2002, the distillate inventory fell below the minimum average amount for the last five years,

Table 2: Average Annual U.S. Energy Prices, EIA Base Case (Nominal Dollars per Barrel) (*italics signify forecast*)

	1999	2000	2001	*2002*	*2003*
Crude Oil Imported	$17.26	$27.72	$22.01	*$23.73*	*$23.94*
West Texas Inter. Spot	$19.25	$30.29	$25.95	*$25.93*	*$25.96*

All data: U.S. DOE-EIA

Table 3: Status of Distillate Oil Stocks Inventory, Late 2002

Stocks end of August 2002	130 million barrels
Stocks end of November 2002	120 million barrels (~ 18 milion barrels lower than January 2002)

due to the colder October and November. Tightened supply with predicted higher oil prices and recovering industrial demand should push the price for distillate up about 10 cents per gallon.

Natural Gas

In March 2002, EIA predicted that during summer 2002, natural gas wellhead spot prices per thousand cubic feet would fall below $2.00. Instead, the wellhead price averaged $2.83 in the third quarter and for all of 2002, the average will be close to $3.00 per thousand cubic feet. Spot prices hit $4.00 per thousand cubic feet in November, and rose significantly in December. January and February delivery prices on December 18th were $5.28 and $5.25 per million Btu. These higher prices should continue throughout the winter months. The winter delivery prices contrast with the average wellhead price EIA projects for all of 2003, which is $3.69 per thousand cubic feet. Overall demand for gas in 2003 is projected to rise 3.6 percent. Earlier in 2002, EIA projected industrial demand for natural gas to rise by 9.6 percent in 2002, and another 6.3 percent in 2003. Domestic dry gas production in 2002 should be 1.6 percent lower than 2001. EIA projects it to rebound by 2.7 percent in 2003 as demand rises and inventories fall to normal. Working natural gas in storage was 2.95 trillion cubic feet in November, nine percent below the level at the same time in 2001. Through 2003, natural gas in storage is predicted to be above the five year average until the end of the year, when it will drop below it.

Active rigs drilling for natural gas were 43 percent lower in August 2002 than 12 months previously.

Although no gas price spike ($9.00/MCF) is foreseen similar to the one that occurred in winter 2001, the EIA projection range plotted for 2003 now indicates that the base case wellhead price should be well over $4.00 per thousand cubic feet in early 2003, and the range shows that it could possibly reach a high of near $6.00 before falling

Table 4: Natural Gas Demand (trillion cubic feet) (*italics signify forecast*)

	2000	2001	*2002*	*2003*
Total U.S. Demand	23.44	22.41	*22.21*	*23.11*
Annual Industrial Demand	n.a.	9.00	*9.86*	*10.43*

All data: U.S. DOE-EIA

Table 5: Summary of Natural Gas Production, 2001-2002

	2001	2002
Average domestic production per month	1.62 trillion ft^3	1.59 trillion ft^3
Net imports per month	0.30 trillion ft^3	0.28 trillion ft^3

All data: U.S. DOE-EIA

Table 6: Coal Receipt Prices ($/short ton) at Selected Manufacturing North American Industry Classficiation System Category

	Apr-June 2001	Apr-June 2002	Change
Paper	$41.93	$43.88	+ 4.6%
Chemicals	$36.38	$40.02	+ 10.0%
Primary Metal*	$27.41	$28.19	+ 2.8%
Avg. All Industries	$31.89	$33.43	+ 4.8%
*Excludes coke [At 25 MMBtu per short ton bituminous coal $33.43 = $1.34/MMBtu]			

All data: U.S. DOE-EIA

as summer approaches. The lower boundary of the predicted range for 2003, is about $2.50 during the summer months. In other words, gas price uncertainty remains pretty high. The drilling rig count remains low, and the gas industry is finding that many wells dug from existing bore holes are delivering gas for a shorter period of time than historically. Some speculation about adequate gas supplies has begun to surface, but the gas industry appears confident that higher prices will ensure adequate supply.

Coal

In the March 2002 DOE Short-Term Energy Outlook, the only EIA statement regarding coal predicted a continuing slow price decline through 2003. The September report did not mention coal. Demand for coal is set by the utility sector, which consumes 87percent of U.S. coal production (56 percent of electricity is generated by coal plants). Total U.S. coal supply, net of imports and exports, was 1,090.4 million short tons in 2001 and was forecast to drop to 1,054.7 million short tons in 2002, and drop again in 2003, to 1,052.6 million short tons. Demand for coal was projected to rise 0.8 percent in 2002 and 1.1 percent in 2003.

Total industrial coal consumption for coke plants was 26.1 million short tons in 2001 and should decline to 23.5 million short tons in 2002. EIA expects coke plant consumption to recover somewhat to 24.3 million metric tons in 2003. Non-utility independent power producer demand for coal, excluding cogeneration, was 150.6 million short tons in 2001, and is forecast to grow to 192.7 million short tons in 2002 and 197.1 million short tons in 2003. Retail and general industry use, which was 67.5 million short tons in 2001, is forecast to drop slightly to 65.3 million short tons in 2002 and decline again in 2003 to 65.0 million short tons. Western low sulfur coal production is forecast to rise 2.5 percent per year through the next two decades while higher sulfur eastern coal production is projected to remain level. Contrary to EIA's expectation that coal prices will continue a decline, over the last 12 months, for all industries, they have actually risen 4.8 percent.

Restructuring of electric utilities is expected to keep pressure on coal producers and railroads to cut costs. The coal industry may further consolidate in response to a utility movement to negotiate shorter term contracts for coal. Coal producers may need to take steps to manage a higher level of risk and coal futures markets are being created in some regions. In short, restructuring in the electric power sector could have a spillover effect on the stable coal market.

Implications for Marketing Industrial Steam Efficiency

The U.S. electric power sector, which reached a record production high in August (source: Edison Electric Institute), demonstrated its flexibility to adjust to fuel price changes. In 2002, total oil-fired generation is expected to be 30 percent lower than in 2001, while natural gas use is projected to increase 7.2 percent compared to 2001. In the industrial sector, unlike utilities, natural gas dominates energy consumption. EIA 1998 data for all manufacturing industries show the following fuel consumption figures, in trillion Btu, in Table 7.

Environmental emissions associated with conventional coal combustion remain a brake on fuel switching, unless industry were to adopt coal gasification or best available technologies to control air pollution.

Table 7: U.S. Industrial Fuel Consumption (Trillion Btu), 1998

Natural Gas	LPG & NGL	Coal (excl. coke & breeze)	Residual Fuel Oil	Distillate Fuel Oil
6,644	135	1,143	357	133

All data: U.S. DOE-EIA

Industrial firms may be feeling somewhat secure about gas supply. The California utility "crisis" was partly created by trader manipulations and supply has met demand this year without strain. Furthermore, gas imports only account for 15 percent of U.S. demand, almost all of which comes from Canada, which increases confidence in domestic supply stability. It is not likely that industry is very aware of a debate now being conducted about the timing of global peak oil and gas production, and the impact that a two percent per year increase in natural gas use in the U.S. will have on supply if the peak in gas use occurs in 15 years rather than 35. The gas industry believes it will be able to deliver 30 trillion cubic feet per year, but there is more need to track trends at this time for decision makers.

Gas industry conditions in the U.S. have established a dynamic that promotes cyclical price movements. First, short-term supply and demand for gas is relatively inelastic. In periods of scarcity or abundance of supply, prices move a great deal. Second, gas producers experience large fluctuations in cash flows, investments and available supplies at the wellhead due to the large price movements. This perpetuates the situation. Third, the gas industry is likely to over-invest relative to gas demand when prices are high and under-invest when they are low. This is due to the significant amount of time between changes in price and changes in wellhead gas supply, typically 6 to 18 months. Finally, some gas producers are now experiencing more rapid dropoffs in production from new natural gas wells. If production declines faster than anticipated in these new wells, producers may get caught short if they have cut investment in developing new capacity. The near-term outlook for industrial users is to expect significant price fluctuations. It may be some time, if ever, before the market sees $2.00 per thousand cubic feet gas.

Government policy is also likely to have a larger impact on natural gas supply and therefore, demand. Estimated total undiscovered, technically recoverable natural gas resources off the coasts of the mainland U.S. are about 235 trillion cubic feet. Of this amount, about 60 trillion cubic feet are currently inaccessible due to policy. The Rocky Mountain resources currently on federal lands and inaccessible represents another 30 trillion cubic feet. A third factor will be imports of liquefied natural gas (LNG). They have been rising rapidly and in the future could rise and fall to mitigate price swings related to domestic supply. In short, there is more uncertainty about natural gas supply now than in recent years and industry decision makers should follow trends with more attention when making decisions about energy-related investments in their plants.

Congress adjourned in 2002 without passing national energy legislation. With the Republicans now holding both Houses, an energy bill should emerge in this session. The Bush administration has also adjusted New Source Review EPA regulations that may make it easier for companies to invest in equipment upgrades that will include more efficiency. It should be noted that the supply-oriented National Energy Strategy document the Bush administration produced had little to say about industrial efficiency, but the energy legislation could include financial incentives for energy conservation investments that will pertain to industry. The picture will not become clearer until Congress organizes and the FY2003 appropriations bills are finally passed. In the meantime, potential to promote steam efficiency to reduce NO_X emissions and enhance compliance with clean air requirements is growing stronger in certain areas of the U.S.

Near-term gas price is another matter and EIA has forecast a significant increase in gas prices in 2003 as the economy recovers and colder weather increases demand this winter. Prices will also be affected by the decline in U.S. gas production in 2002 and the inevitable link with current oil prices, which at the end of 2002 have gone over $30 per barrel. Will these higher prices stimulate investment in steam efficiency? Probably not. Company managers are contending with excess production capacity, lower sale prices for their products and serious erosion of their stock value. This economic environment is more likely to stimulate quick and easy cost cutting. Given a thinning of staff capabilities in many companies, energy conservation may have a hard time getting on the "quick and easy" cost cutting list. Indeed, training companies have indicated that companies are restricting travel, a sign that the general environment for increasing efficiency remains difficult. Conservation proponents might argue that low interest rates should justify borrowing to invest in energy saving projects that would lower bottom-line costs and repay the loans easily. Unfortunately cost cutting to retain profits on a smaller volume of sales probably will not stimulate allocation of internal capital for energy efficiency improvements.

Looking a little further ahead, an intervention in Iraq might disrupt oil supply for a short time, but Iraq's one to two million barrels per day of oil sales can easily be made up by OPEC. Iraq has very large oil reserves, so if the S. Hussein government is replaced, Iraqi oil sales could double in a short time and prices would then drop. If high gasoline prices triggered, as usual, consumer action to conserve energy, industry may respond for a short while by deciding to give more priority to energy investments. The likelihood that oil price rises would be short-lived suggests, however, that more stimulus to invest in steam efficiency will result in a true rebound from the downturn in the industrial sector.

References

1. U.S. Department of Energy, Energy Information Administration: *EIA Annual Energy Outlook 2002 with Projections to 2020.*
2. Web page: "Short Term Energy Outlook– March 2002" www.eia.doe.gov/emeu/steo/pub/contents.html.

An Analysis of Steam Process Heater Condensate Drainage Options

James R. Risko, TLV Corporation

Abstract

The production and reliability of performance of steam process heaters can be significantly affected by the condensate drainage design that is employed. The current variety of drainage options can be confusing to a system designer who is unaware of the reasons for each specific design. An understanding of the various types and why they may be used follows.

Background

For simplicity, the terminology "process heater" is intended to mean any steam heat exchanger, coil, or kettle which uses steam as the primary fluid to transfer heat to a product. While generally intended for production purposes, this terminology can also be used to refer to HVAC applications. The reason that all of these heater types can be grouped together is because even though they incorporate different exchanger designs on the product side, they all are intended to transfer steam heat in an efficient and cost effective heating manner. In that sense, they all use the steam to provide a certain level of heat transfer and drain the by-product, condensate, away from the heater so that new steam can be introduced and controlled to heat additional product.

What is intriguing about this simple goal is that there are currently a variety of installation designs to accomplish the removal of that condensate, and these provide various levels of production performance depending on the environmental conditions of the specific heater application. What can be confounding is that some of these drainage options may work very well in one scenario, and yet fail miserably in another depending on the conditions. When successful in a previously troublesome application, a particular installation design may create a sense of comfort within an engineering department and later become a standard practice for a facility. Later it can have decidedly mixed results when used for an application for which it cannot perform well enough to meet design expectations. This situation may have tremendous energy and production implications and can usually be easily identified in advance.

Identifying the Symptoms

Telltale signs for those installations with unsuitable condensate drainage include:

- Condensate being visibly wasted from the heat exchanger discharge side, either from a hose connection at the strainer, or an opened union or drain valve on the steam trap's outlet piping. In this case, the condensate is no longer available to be returned through the return line, and its valuable energy is needlessly sacrificed to grade so that required production performance levels can be achieved.
- The presence of severe hammering in the exchanger itself or in the return piping downstream of the heater. There are a variety of causes for this type of hammering, but in the worst case its cause can be attributed to significant amounts of preventable steam loss.
- Product variance much greater than expectations.
- Dramatic temperature stratification of the heater's exterior surface where steam is shell-side.
- A higher than average maintenance requirement for head gasket or tube bundle failure.

Course of Action

The optimum solution is to specify a condensate drainage design that removes all condensate from the heater rapidly. This is where confusion over the best design has traditionally occurred. While the target of high performance heat exchanger installation design prevails, a full understanding of the options and when their use is indicated is often not clear.

Therefore, the purpose of this presentation is to examine the common types of heat exchanger drainage designs, and describe the instances where each can perform suitably. Those installation designs are slightly different when steam is tube-side versus shell-side, and the piping options for both instances follow:

Potential Installation Designs

- Steam Inlet Control Valve with Outlet Steam Trap (Figure A).
- Steam Inlet Control Valve with Outlet Level Pot (Figure B).
- Steam Inlet Control Valve with Outlet Condensate Level Control (Figure C).
- Condensate Outlet Control Valve and Level Override (Figure D).
- Condensate Outlet Control Valve for Drainage and Set Point Control (Figure E).
- Steam Inlet Control Valve with Outlet Condensate Pump/Trap Drainage (Figure F).

An in-depth knowledge of the various options will help in providing the most effective condensate drainage installation for each given circumstance. With a clear understanding of these options and when to use them, the designer will be able to maximize the energy usage and production performance of each application according to the budgetary constraints of the allocated capital.

Steam Inlet Control Valve With Outlet Steam Trap (Figure A)

This is the traditional approach to supplying steam and drainage condensate from process heaters. It offers a relatively simple installation, with easy troubleshooting and low cost maintenance. It accomplishes the control value by modulating steam temperature and rapid drainage of condensate from the tube bundle. It is the primary method of choice where the pressure supplying the steam trap (P1) is always greater than the back pressure (P2) because it always keeps steam on the tube bundle under these conditions. The figure shows condensate draining by gravity, but this is not an actual requirement. Condensate can elevate with this design, and it can operate against back pressure, provided that the differential from P1:P2 is always positive.

Is the differential pressure really positive?

The actual pressure differential P1:P2 may not really be positive when it appears to be so. For a true understanding, it is necessary to study the pressure dynamics of the control valve as it modulates to achieve the heat balance with the set point. As the heating demand lowers, the control valve will modulate and lower the pressure in the steam space. When this occurs, P1 will often become lower than P2 even though the supply pressure to the control valve is substantially greater than P2. This condition where P1 modulates a lower pressure than P2 is known as a "stall". The effect is that Figure A's installation design can work very well in all cases until it is used in applications where stall occurs. Then the system will provide less desirable results.

What happens during "stall"?

The system partially floods the tube bundle. This creates a variety of undesirable effects, including inconsistent product quality and large variations from the set point. Other typical symptoms include corrosion, thermal shock, and hammering of the heater with damage to either the heater itself or the outlet steam trap.

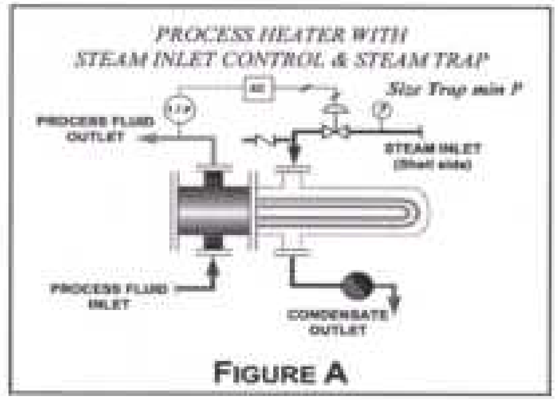


Figure A

Steam Inlet Control Valve With Outlet Level Pot (Figure B)

This system is basically a modification of the installation shown in Figure A. It has been used as a steam trap substitute in applications of very high pressure and high capacity where these requirements are beyond the capabilities of a traditional steam trap. It has also been used for instances where "stall" occurs and the resulting hydraulic shock has severely damaged the outlet steam trap.

The only difference between the systems shown in Figure A and Figure B is in the design of the trap. Figure A uses a traditional, self-contained steam trap, and Figure B substitutes an electronic steam trap in the form of a level pot receiver, level sensing from the transmitter, and automatic valve opening and closing through the controller and control valve. Although a more complex system, the condensate drainage function is virtually identical to a simple, mechanical steam trap. Generally, the cost of this electronic steam trap option is greater than a self-contained trap.

Because of the durability of the components, this system can improve the symptom where a self-contained steam trap has been regularly damaged from severe water hammer, but it does not correct the cause. In this sense, it is only a band-aid, and additional symptoms of corrosion and production variance from the control value will not be corrected by this option.

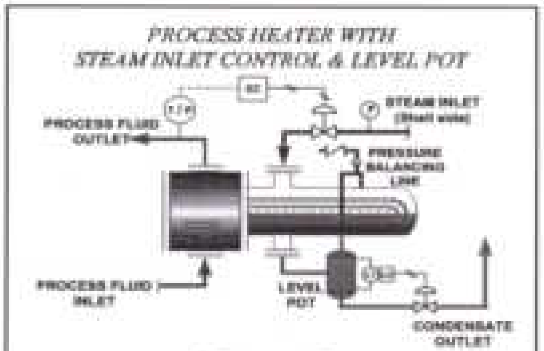


FIGURE B

STEAM INLET CONTROL VALVE WITH OUTLET CONDENSATE LEVEL CONTROL (FIGURE C)

This solution has been used in some cases to combat stall conditions. In this case, a sufficiently high steam pressure is used on the control valve inlet to ensure a positive pressure differential P1:P2. Because of the possibility of large pressure and temperature changes, some heater surface area is removed by intentional flooding. Limiting the effective surface area in this manner can lower the range of the control swing.

This insulation will provide positive pressure differential for P1:P2, but causes increased fouling on the tube bundle which is usually exposed to high pressure steam. Troubleshooting this installation will be complex, and corrosion, head gasket failure, and thermal shock can be expected maintenance issues because the tube bundle is stratified with condensate and steam.

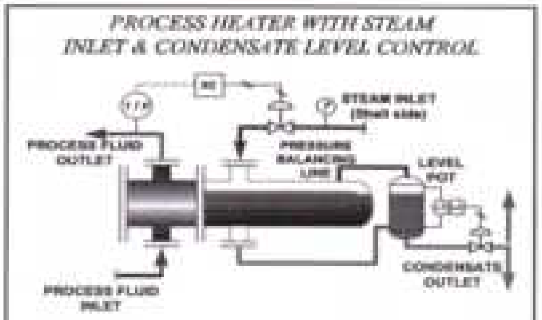


FIGURE C

CONDENSATE OUTLET CONTROL VALVE AND LEVEL OVERRIDE (FIGURE D)

A common alternative used by some design engineers is to completely eliminate inlet steam control and select outlet condensate control instead. In this design, the outlet control serves as both control valve and steam trap. The installation does not stall because the steam pressure does not modulate. The result is that the pressure on the tube bundle is always greater than the back pressure. The level pot is used to reduce the possibility of live steam loss, and the tube bundle is intentionally flooded to remove excess surface area. Then the available tube bundle area becomes the control variable.

Under stall conditions, this system can be a lower cost alternative than the steam inlet control and outlet level pot design of Figure B. The outlet control and level pot are actually sized similarly to Figure B, but this system completely eliminates the cost of the inlet control valve. Additionally, the heater is exposed to higher pressure steam at all times, so its required surface area may be reduced due to the expected higher temperature of the unmodulated steam.

This system can provide acceptable process control in instances of limited demand variation. However, the more the demand changes, there may be instances of significant deviation from the control value. This is due to at least two factors. Changing water level on a tube bundle is a much slower process than adjusting steam pressure. Therefore, the process to adapt to demand changes in an outlet control design by moving a water level is significantly slower than when moving steam that occurs in steam inlet control installations. The result is a greater lag in response to demand changes. Also, once the water level is moved, the newly exposed or covered heat transfer area encounters a drastically changed “U” value. This is because of the substantially different heat transfer rates between hot condensate and steam. The effects of this difference will be in proportion to the amount of new surface area exposure. The more the demand change and subsequent tube exposure, the more dramatic the change in “U” and the resultant variation from the control value. In short, wider temperature or pressure swings are typical of this control method.

An additional issue with this design is that the heater’s life begins with intentional flooding, then exposes increasingly more area as the tube surface becomes fouled. Eventually, the entire surface can become exposed and still not satisfy the process demand due to fouling. Then, such systems programmed with a level override priority can actually blow live steam through the control valve, thereby pressurizing the return line. This leads to a high energy cost and detracts from the production rate of all other heaters draining into the increased back pressure of the same return heater.

Additionally, without any special provisions, the heater will remain flooded at shutdown and tube corrosion will be exceptionally high in these cases.

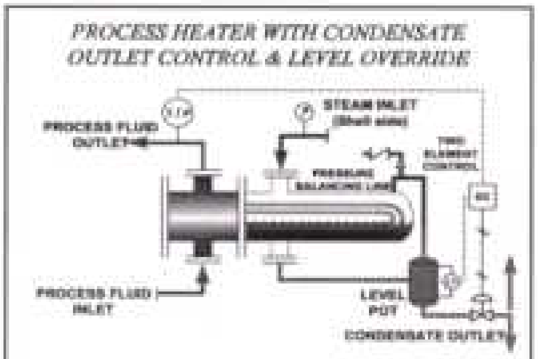


FIGURE D

Condensate Outlet Control Valve for Drainage and Set Point Control (Figure E)

This installation is virtually identical to Figure D, except that the cost and leak protection of the level pot is eliminated. The installed cost is lower by this elimination, but the energy consumption can be significantly higher due to live steam loss throughout the heater life. All other characteristics of Figure D remain.

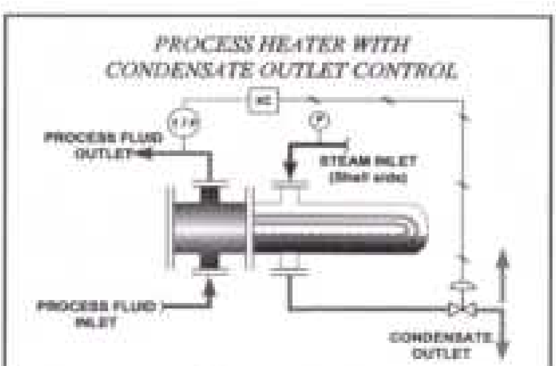


FIGURE E

Steam Inlet Control Valve With Outlet Condensate Pump/Trap Drainage (Figure F)

The installation in Figure A is a perfect design in which stall and hydraulic shock conditions do not occur. However, for those severe conditions, Figure A cannot be used, and the other designs of Figures B through E were most likely developed to deal with them. Unfortunately and for the reasons explained above, those other designs are not always optimal when dealing with stall. Figure F provides a suitable maximum benefit design for stall conditions.

The system utilizes a piece of equipment known as pump/trap combination. This can be either a single combined pump/trap unit, or employ two separate products in an engineered package. Usually suitable for pressures up to 150 psig steam, pump/traps allow the system to adapt quickly to demand changes and drain condensate under all pressure conditions.

The design requires that inlet steam control is used. This is to provide for the most rapid adjustment to demand changes possible. In an inlet steam valve installation, the control valve adjusts the steam pressure and temperature rapidly, as soon as the sensor detects a variance against the control value. Condensate is always drained from the system by the pump/trap, so the exposed surface area is constant allowing the modulated steam pressure to equalize to the required load. The pump/trap has a multi-functional capability.

As a Trap. When the pressure differential of P1:P2 is positive, the steam space pressure drives condensate through the unit, and steam is contained by the included trap. Operation under these conditions is similar to Figure A.

As a Pump. When the pressure differential of P1:P2 is negative, then the condensate fills the pump cavity and is pumped downstream before the process heater can be flooded. The result is that the heater tubes are always exposed only to steam and not to flooded condensate. The main point is that only the small pump body receives high pressure steam, not the entire process heater as occurs in Figures C, D, and E.

Where suitable to be employed, Figure F systems of steam inlet control and pump/trap drainage minimize energy waste, high control variance, corrosion, thermal shock, and stratification during production. When properly designed, they also drain the equipment during shutdown to avoid the high corrosion that occurs from stagnant condensate. They can minimize fouling as the steam temperature used is always the lowest possible to achieve equilibrium with the demand. The motive steam used to pump the condensate in the system is returned to the process heater to utilize its heat in the process. This guarantees an extremely low cost pumping solution while maximizing the production rates of steam process heaters.

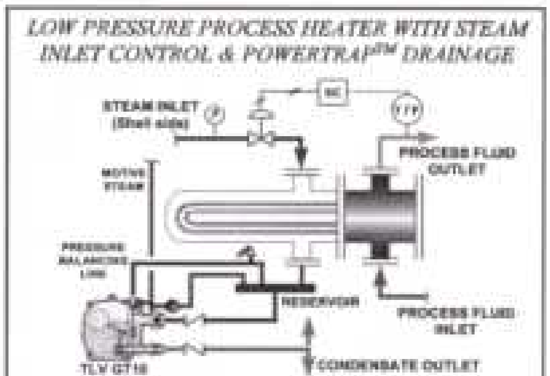


FIGURE F

CONCLUSIONS

The author's preference is for the drainage methods of Figure A and Figure F as primary solutions, and then Figure B when neither of the first two alternatives will meet the application requirements. In cases where neither Figures A, F, or B will meet the application demands, then Figure D may be considered provided that the user accepts the limitations of this design.

ACKNOWLEDGMENTS

The PowerPoint graphics included with this paper were drawn by Mr. Tracy Snow and Mr. Steve Kortheuer, both Sr. Engineers in TLV's Consulting and Engineering Services Department.

REFERENCES

1. Mathur, Jimmy, 1973. "Performance of Steam Heat-Exchangers", *Chemical Engineering*, September 3, pp. 101-106.
2. McCarthy, Alfred J. & Smith, Brian, R., 1995. "Reboiler System Design: The Tricks of the Trade", *Chemical Engineering Progress*, May, pp. 33-47.
3. Mehra, Davinder K., 1985. "Troubleshooting Problems With Heat Exchangers", *Chemical Processing*, August, pp.36-38.
4. Pathak, Vijay K. & Rattan, Inder S., 1988. "Turndown Limit Sets Heater Control", *Chemical Engineering*, July 18, pp. 103-105.
5. Risko, James R., 1997. "Maximize Productivity From Steam Process Heaters Through Proper Condensate Drainage", *TLV Design Guide*.
6. Risko, James R., 1996. "Managing Steam Condensate is Key to Heater Efficiency", *Chemical Engineering*, July pp. 114-119.
7. Risko, James R., 1996. "Draining Condensate From Steam Process Heaters", *Plant Engineering*, March, pp. 74-76.
8. Risko, James R., 1994. "Complete Condensate Drainage From Equipment", *TLV Design Guide*.
9. Risko, James R., 1988. "Handling Steam Condensate", *Plant Engineering*, March 10, pp. 146-149.
10. Schwartz, Marvin P., 1982. "Four Types Of Heat Exchanger Failures", *Plant Engineering*, December 23, pp. 45-50.

Combustion Control Strategies For Single and Dual Element Power Burners

David C. Farthing, Federal Corporation

Today's economic and environmental demands dictate that we get the greatest practical efficiencies from our plants. To do this we must have a basic understanding of what those efficiencies are and how we may implement them.

The use of more advanced automatic control systems for combustion control has proven to be an excellent example of systems and process automation success. The new control systems available today help improve overall combustion efficiency and burner stability over varying loads and demands. The most sophisticated systems can eliminate the need for operator input during load changes while maintaining safe and reliable fuel-air ratio control.

The Combustion Process

The most common fuels used in single burner commercial and industrial boilers are natural gas and No. 2 oil. Both of these fuels consist of carbon and hydrogen. Combustion is the rapid oxidation of the fuel to release the chemical heat energy in the carbon and hydrogen. Stoichiometric, or perfect, combustion occurs when the exact proportions of fuel and oxygen are mixed to obtain complete conversion of the chemical energy in the carbon and hydrogen to yield maximum heat energy. These ideal proportions of fuel and oxygen vary directly with the Btu content of the fuel. Too much excess oxygen cools the flame and increases NO_X pollutants while too little oxygen results in incomplete combustion and sooting of the furnace or delayed combustion, which can result in a furnace explosion.

Fuel	Caloric Value	Ideal Volumetric Air / Fuel Ratio
Natural Gas	900 - 1050 Btu/CuFt.	9.71 CuFt. Air to 1 CuFt. Fuel
No. 2 Fuel Oil	138 - 140,000 Btu/Gallon	1355 CuFt. Air to 1 Gallon Fuel

Because of the specific design restrictions or lag times inherent in current burner design, a certain amount of excess air (oxygen) is always required to insure complete combustion in the furnace chamber. These restrictions take the form of delays in fuel and air flow due to friction losses in piping or lag times in the control elements. Additional influences may be in the form of site location elevation, the effects of combustion air temperature, humidity and availability, or fuel pressure and Btu content.

These design restrictions dictate some form of fuel-air metering control for safe and efficient combustion control. The systems available for this task vary in sophistication from the simplest fixed position control system to the elegant metered-cross limited fuel-air ratio control systems. This paper discusses the benefits of several of these systems as they apply to single burner packaged boilers.

Combustion Strategies

Fixed Position Parallel Control

Fixed position parallel control (FPC), also known as direct of jack-shaft control, is perhaps the simplest form of combustion control found on power-burner boilers. This control strategy incorporates a single positioning motor, which drives both the fuel and air positioning devices via an interconnected single mechanical linkage, the jack-shaft.

The simplicity of the FPC strategy makes it a very economical choice for small burners with modest firing rate changes. However, the fact that the fuel and air are fixed means that the fuel-air ratio is also fixed. Because of this fixed position arrangement the burner has no way to compensate for environmental changes such as combustion air temperature or fuel pressure. Additionally, the FPC strategy has no feedback to the control element to insure that the fuel and air end devices are actually functioning and in the correct position. This could lead to a crossover condition in which the fuel crosses over the air flow and results in a fuel rich furnace or other burner efficiency loses.

To help prevent a fuel rich furnace the FPC system is setup to allow additional excess oxygen to the furnace, in the range of 4.5 to 8 percent. In practice the excess oxygen is normally set at 6-7 percent to compensate for seasonal air temperature changes. This excess air results in lower ther-

Figure 1: Fixed Position Parallel Jack-Shaft combustion system with fuel-air ratio established through fixed mechanical linkages

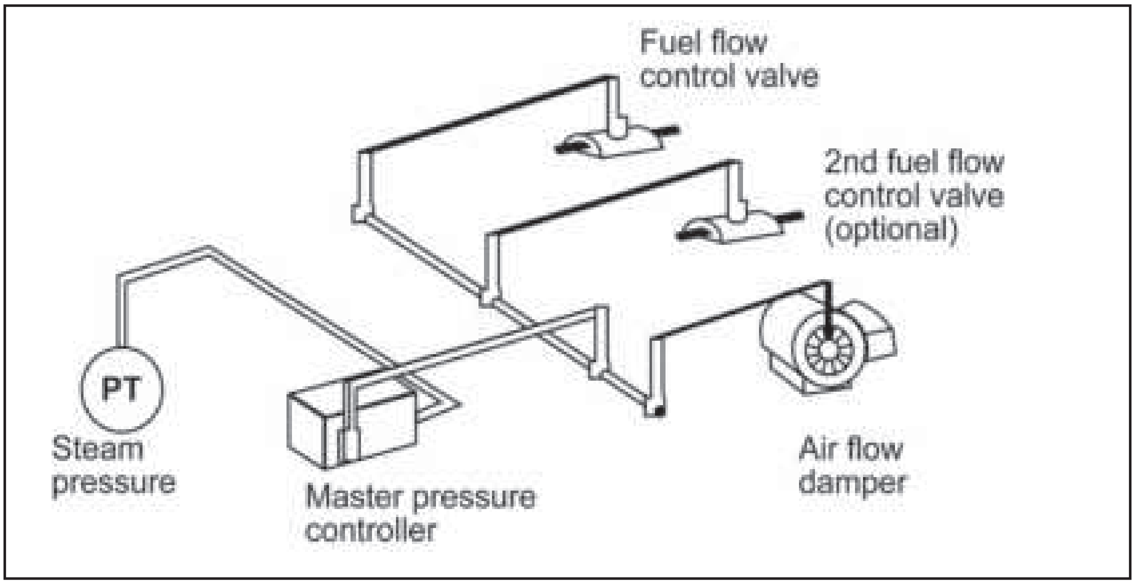
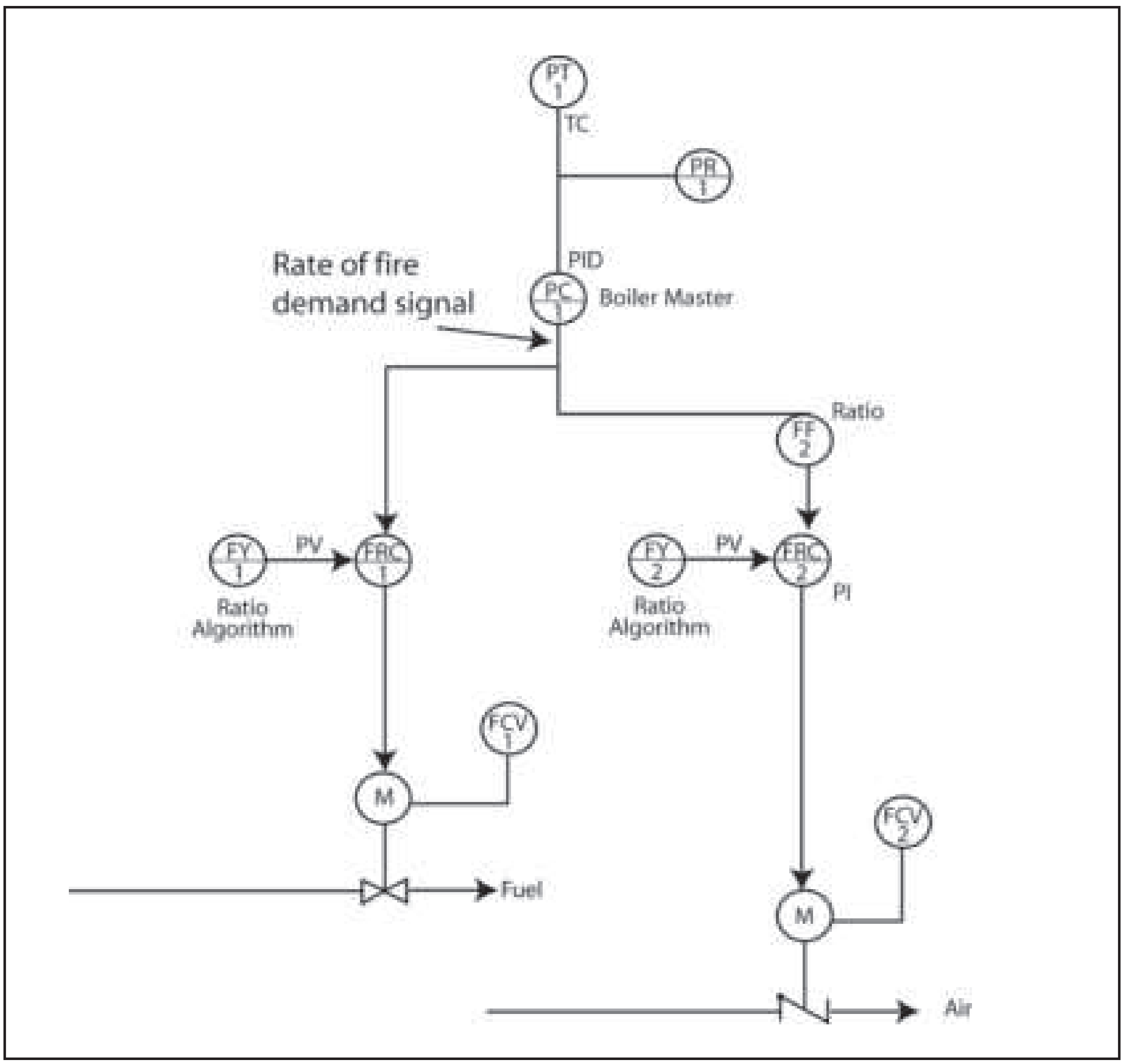


Figure 2: Parallel Position



mal efficiency by burdening the burner with unnecessary air, which only serves to cool the furnace and increase NO_Xproduction.

Parallel Positioning Control Systems

Parallel positioning control (PPC) systems function very much like a Fixed Position Parallel system except that the fuel and air end devices are separated and driven by their individual positioners. Modern electronic PPC systems incorporate an end-device-positioning signal, which ensures the fuel and air positioners have moved to their pre-specified positions for a specific firing rate. This signal, while not actually proving final end device position and true fuel-air ratio flow, is a market improvement over FPC systems.

The new systems are gaining wide acceptance with many users who have traditionally used FPC systems and are seeking an economic means to improve overall combustion efficiency. The modern PPC system is suitable for boilers ranging from 100 through 900 boiler horsepower operating with relatively stable loads. Larger systems are also becoming more prevalent.

Modern electronic positioning PPC systems can hold excess oxygen levels to within 3-4 percent on many applications. It should be noted however, that when holding excess oxygen levels to these minimums the PPC control strategy should be used with caution in applications with extremely fast load swings. Controllers and positioners, which might be set too tight may not properly respond and still maintain a safe fuel-air ratio on large and very fast upsets. This is due in part to the lack of process variable feedback in the fuel-air system.

And like the FPC system, it is impossible for the PPC system to compensate for any changes in fuel or combustion air characteristics. Thus, issues such as fluctuations in fuel pressure, air temperature or humidity will have adverse effects on combustion processing using this system.

Series Metered Control System

The series metered control (SMC) is common on larger boilers (above 750 Bhp) where load changes are neither large nor frequent. In this application both the fuel and the air are metered. The Boiler Master regulates combustion air flow by setting the air flow setpoint. The air flow controller then cascades the air flow signal to the fuel controller as its remote setpoint. A ratio algorithm is applied to the remote setpoint signal sent to the fuel controller to adjust the fuel-air ratio. The ratio algorithm compares the remote setpoint cascaded to the fuel controller by the air flow and positions the fuel flow control valve to maintain the specified ratio between the two.

This ratio algorithm has an inherent lag in it due to the fact that the air controller is always directing the fuel controller's function; air always leads fuel. This lag provides a desirable lean furnace on demand rise, as the air controller must respond to the Boiler Master before sending a remote setpoint

Figure 3: Series Metered Fuel-Air Ratio Control

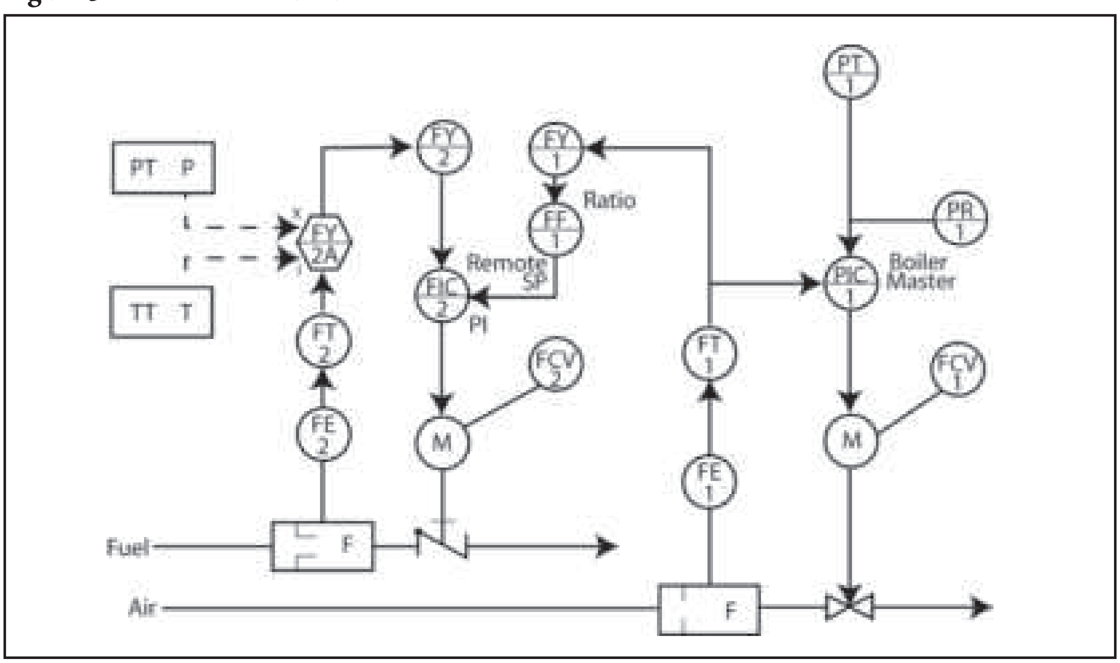
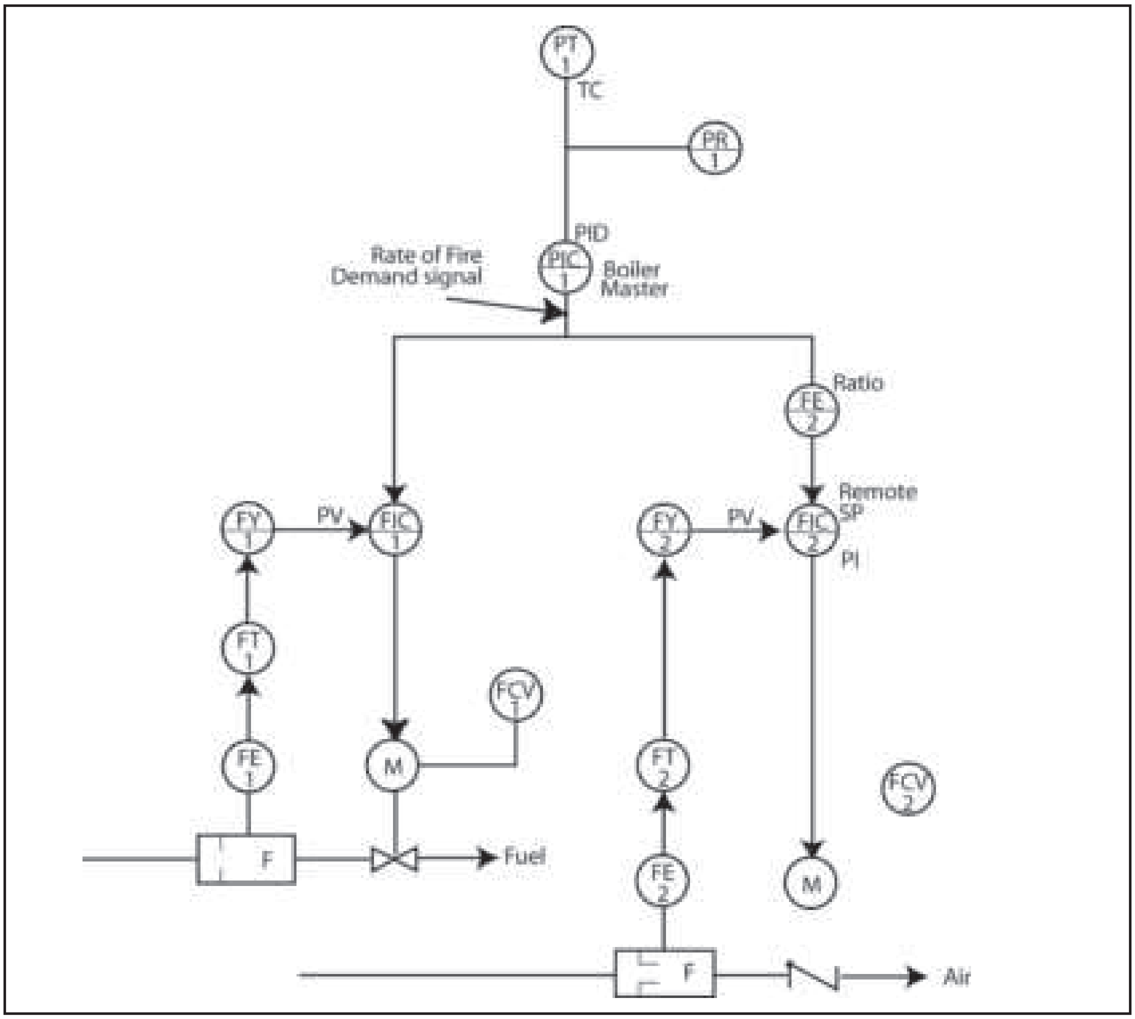


Figure 4: Metered Parallel Fuel-Air Ratio Control



to the fuel controller. However on a fast-falling demand the lag between the air controller and fuel controller can result in the air flow overshooting the fuel flow resulting in a crossover-fuel rich furnace.

Because of this lag characteristic, the series control system is only adequate for near steady state conditions due to its inability to react to fast falling load swings. To compensate for these possible overshoots and lag times, excess oxygen levels in series control systems are normally set at 5-8 percent. The use of an oxygen trim system is then incorporated to adjust the excess oxygen levels down to 3-4 percent during steady state operation.

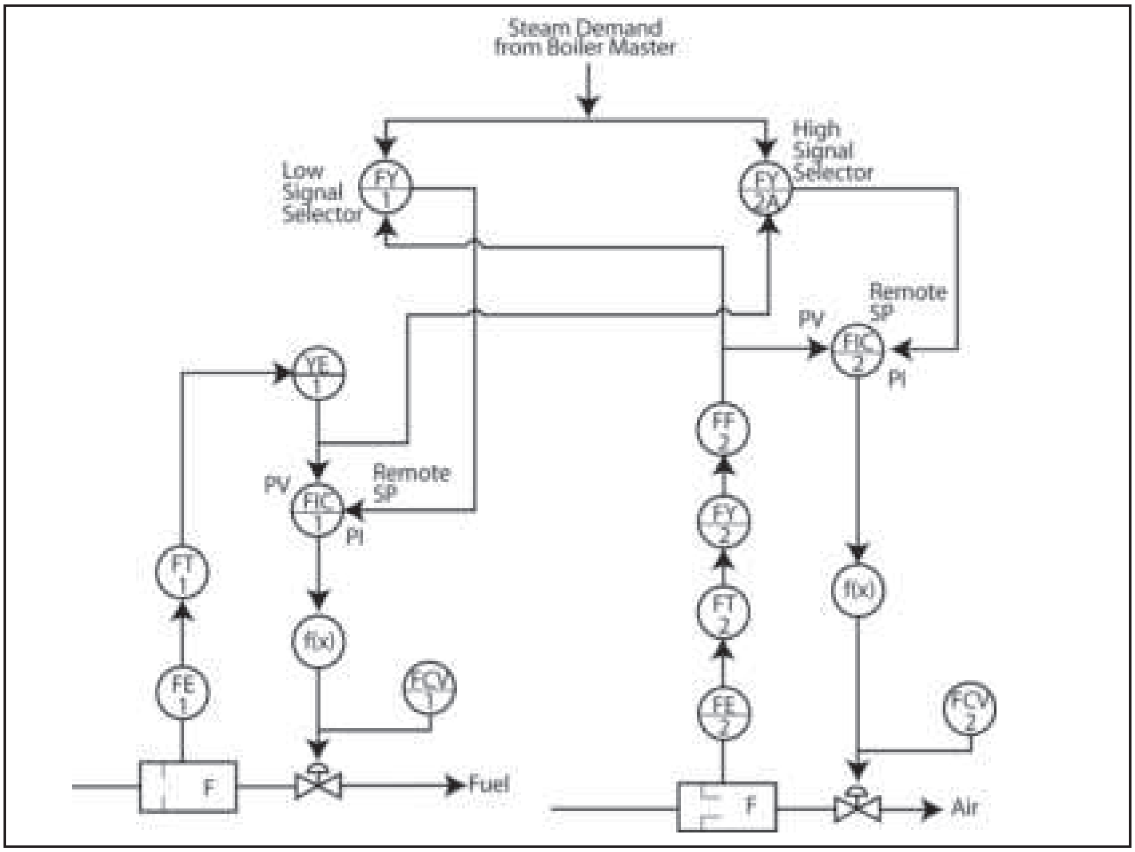
Significant improvements in the accuracy of the flowing process variables fuel and air, may be made using SMART temperature and pressure compensated transmitters, thus improving the overall accuracy of this and subsequent metered systems.

Metered Parallel Positioning Control

Boilers operating at 1,000 boiler horsepower and above commonly incorporate the metered parallel positioning control system. The metered parallel positioning control (MPPC) operates the fuel and air control loops in parallel (as opposed to series) from a single setpoint generated by the boiler master controller. The combustion air setpoint is ratioed which establishes the fuel-air proportions.

By allowing for customization of the fuel-air ratio the amount of excess oxygen in the exhaust gases may be reduced to about 3-4 percent as opposed to the 5-8 percent normally found in the series metered control strategy. In practice however, the excess air is set at about 4.5-5 percent to compensate for barometric changes in air density. The use of an oxygen trim system is then incorporated to adjust the excess oxygen levels down to 2.5-3 percent during steady state operation.

Figure 5: Cross Limiting or Lead-Lag Fuel-Air Ratio Control



The MPPC system relies on near identical response from both the air and fuel control loops to prevent fuel rich or air rich mixtutres in the furnace. The difficulty in maintaining this near identical response limits the application of the MPPC system to applications with modest demand swings.

Like the Series system, the traditional MPPC system does not have any feedback to the opposing flow controllers, i.e., fuel does not recognize air and air does not recognize fuel. This absence of feedback can result in a combustion imbalance on large or very fast load swings, resulting in either a fuel-rich or lean furnace. To compensate for the lack of feedback found in the MPPC, these systems are normally set-up with additional excess air to over compensate for fuel flow during setpoint excursions, thus maintaining an air-rich furnace on transition.

Cross-Limited Metered Control

Cross-limited metered parallel positioning control, (a.k.a. cross-limited control (CLC) or lead-lag control (LLC)), improves on the MPPC strategy by interlocking the fuel-air ratio control through high and low selectors. This interlock function prevents a fuel-rich furnace by forcing the fuel to follow air flow on a rising demand, and forcing air to follow fuel on a falling demand.

The CLC system is a dynamic system, which easily compensates for differences in response times of the fuel and air end devices. This flexibility allows its use in systems that experience sudden and large load swings, as well as very precise control at steady state operation.

The CLC operates as follows. In steady state, the steam demand signal, fuel flow and air flow signals to the high and low selectors are equal. Upon a demand increase the **low** selector applied to the fuel loop forces the fuel flow to follow the lower of either the air flow or steam demand setpoint. Conversely on a falling demand the **high** selector applied to the air controller forces the air flow to follow the higher or either the fuel flow or demand setpoint. This high/low selector function insures that the burner transitions are always air rich/fuel lean thus preventing a fuel rich furnace environment.

The cross-limited control system can easily maintain excess oxygen levels in gas burners to 3-4 percent and 2.5-3 percent in No. 2 oil systems. Additionally, since fuel flow cannot increase (cross-limited) until air flow has begun to increase, fuel cannot overshoot air flow. The use of an oxygen trim system is then incorporated to adjust the excess oxygen levels down to 2-2.5 percent during steady state operation.

Because of the CLC system's capability for close tolerance control, it is suited for all sizes of boilers, which can support the systems cost economically. Additionally the CLC system is readily adapted to oxygen trim control as well as being suited for low NO_X burner applications.

References

1. Mark's Engineering Handbook, 7th Edition.
2. American Gas Association Research Report 1509.
3. Honeywell Industrial Controls.
4. David. C. Fathing's, "TechStuff", www.federalcorp.com.
5. Jack Schilling, Honeywell Peer-Review.

Insulation Improves Economic Returns in Manufacturing

Christopher Russell, Alliance to Save Energy

If purchased fuel is the "currency" of an industrial plant's energy budget, then mechanical insulation is one of its "savings" components. Just as savings have a specific place in a financial plan for creating wealth, so does insulation play a role in optimizing a plant's valuable energy resources.

According to the U.S. Department of Energy's BestPractices Steam program, mechanical insulation should be used on any surface over 120°F. Boiler surfaces, distribution mains, condensate return pipes and vessels, and hardware fittings should all be properly insulated to conserve thermal resources. Two tip sheets, part of a series of BestPractices Steam tip sheets that currently numbers 19, discuss the benefits of mechanical insulation and demonstrate the calculation of energy savings that it provides (see sidebar).

The value proposition is not the steam itself, but the heat that steam provides. Steam can efficiently and safely dispatch thermal resources from the boiler to multiple locations within a plant, usually to locations appreciably distant from the steam source. Plant managers depend on insulation not only to conserve thermal resources throughout a steam system, but to enhance process stability, ensure personnel safety and to attenuate noise.

Two prime considerations are "whether the insulation is dry and snugly fitted, and whether there is enough of it," suggests Don Wulfinghoff, author of the *Energy Efficiency Manual*. Moisture drastically reduces the heat retention capabilities of insulation. But if the insulation system (insulation and protective jacketing) is properly specified and installed for the steam application, moisture penetration will be reduced and the insulation system will remain effective indefinitely.

The performance of the insulation system is maximized when the correct thickness is specified for the application. Energy savings justify insulation up to a certain thickness, beyond which any additional economic or energy savings may not be worth the cost. (See sidebar discussion.)

Sidebar Discussion

BestPractices Steam, a U.S. DOE initiative, generates references, diagnostic software, case studies, and industry outreach events for the benefit of the industrial steam community. A series of 19 steam tip sheets is available. Each is one page, providing an overview of a steam improvement opportunity and an example for calculating its economic impact.

Two steam tip sheets are devoted to insulation use: (1) *Insulate Steam Distribution and Condensate Return Lines* and (2) *Install Removable Insulation on Uninsulated Valves and Fittings*.

Determining the appropriate thickness for a given mechanical component is addressed by 3E Plus®, a free software tool developed by the North American Insulation Manufacturers Association, and distributed by BestPractices Steam.

An insulation energy appraisal performed by a certified insulation energy appraiser can provide an energy user with a comprehensive assessment of the piping and equipment in a facility and provide recommendations that will help save energy, and reduce fuel costs and greenhouse emissions. The DOE has embraced the insulation energy appraisal certification training program available from the National Insulation Association.
See www.insulation.org.

Readers are encouraged to visit the BestPractices website at www.oit.doe.gov/bestpractices.

Steam tip sheets and most other resources are free of charge and may be downloaded from www.steamingahead.org/resources.htm or may be requested from the BestPractices Clearinghouse:
(800) 862-2086 or
clearinghouse@ee.doe.gov.

Potential savings from insulation application and upgrades may reduce fuel consumption anywhere from 3 to 13 percent, according to the U.S. DOE's Industrial Assessment Center program. Results are sometimes dramatic: a Georgia-Pacific plywood plant in Madison, Georgia upgraded the insulation on steam lines to its dryers. This allowed the plant to reduce its steam load by 6,000 pounds per hour and cut its fuel bill. The investment paid for itself in six months.

A recent insulation energy appraisal was performed on a chemical plant in Kentucky. They had a nagging maintenance issue, and over the past five years had discussed and re-discussed the cost and value of fixing and upgrading the insulation on their distribution lines. A $300,000 investment in insulation upgrades yielded a $700,000 savings in fuel costs. Payback for the investment: three years. An added benefit was reduced emissions. (See sidebar discussion on previous page).

By conserving thermal resources, insulation not only saves money but also improves plant productivity. In this sense, insulation *makes* money for the plant. In addition, the expense relief that it provides becomes a new source of cash that can be applied to other processes in the plant, or to marketing and administration. All of these benefits make insulation a priority for manufacturers in a competitive marketplace.

Reduce Fuel Costs - Use the Proper Air-to-Fuel Ratio in Boiler Combustion

Christopher Russell, Alliance to Save Energy
Tony Tubiolo, Alliance to Save Energy

Do you know what the most common energy and cost saving opportunity in a steam system is? According to the results of 41 steam plant audits performed by Enbridge Consumers Gas of Toronto, Canada, the answer is combustion improvement. The 41 audits, which frequently involved multiple boilers in one plant, revealed a total of 45 opportunities for combustion improvement projects involving any or all of the following: boiler tune-ups, combustion control repair, burner repair, and repairs to existing oxygen trim systems. With an average payback period of less than half a year, optimizing steam system combustion is a proven and effective way to reduce operating costs. Combustion efficiency is also a subject addressed by one of a series of BestPractices Steam Tip Sheets produced by the U.S. Department of Energy (DOE) (see sidebar).

A simple, low-cost way of optimizing combustion is to maintain the proper air-to-fuel ratio in your boiler operations. To completely combust the fuel, there needs to be a slight excess of oxygen, since real-life combustion conditions are never capable of achieving the perfect stoichiometric air-to-fuel ratio. Too little air causes incomplete combustion of fuel resulting in excessive soot and fireside fouling, as well as an explosion hazard. Excess air creates fireside fouling and sends thermal resources up the stack. Extremes in either direction create air pollution and costly inefficiency by wasting fuel.

Combustion improvements "are almost universally required," according to Bob Griffin, who leads the Enbridge Consumers auditing effort. A general rule of thumb is that boiler efficiency can be increased by one percent for each 15 percent reduction in excess air or 40°F reduction in stack gas temperature. The appropriate amount of excess air for optimal combustion varies with the type of fuel and burner in a system. The U.S. DOE's BestPractices Steam program asserts that for well-designed natural gas fired systems, an excess air level of 10 percent is attainable.

BestPractices Steam, a U.S. DOE initiative, generates references, diagnostic software, case studies, and industry outreach events for the benefit of the industrial steam community. A series of 19 steam tip sheets is available. Each is one page, providing an overview and an example for calculating its economic impact.

The tip sheet entitled *Improve Your Boiler's Combustion Efficiency* provides further details and an example of the savings realized by optimizing a boiler's air-to-fuel ratio.

An article that details the Enbridge Consumers steam audit findings is included in *Steam Digest 2001*, available for free by calling the BestPractices Clearinghouse (contact info below). Alternatively, the article may be downloaded from http://www.oit.doe.gov/bestpractices/steam/pdfs/ecreport.pdf.

Readers are encouraged to download Steam Tip Sheets and other resources, free of charge, from www.oit.doe.gov/bestpractices and from www.steamingahead.org/resources.htm. Printed copies may also be requested from the BestPractices Clearinghouse: (800) 862-2086 or clearinghouse@ee.doe.gov.

The first step in determining the proper amount of excess air is to measure the current amount of oxygen in the flue gas. This can be done with a gas absorbing test kit or an electronic flue gas analyzer. Two additional measurements required are the temperature of the flue gas and the temperature of the air going into the boiler. Unless you have an electronic tester that calculates the combustion efficiency based on these measurements, you will need to reference an efficiency table or graph for the specific fuel being combusted. Combustion efficiency tables or graphs come with test equipment, are available in reference books, and are included in the BestPractices' *Steam System Survey Guide*, found online at: http://www.oit.doe.gov/bestpractices/steam/pdfs/steam_survey_guide.pdf.

Calculating the Operating Cost Savings

You can demonstrate the amount of money your facility will save by instituting a regular air-to-fuel ratio measurement and adjustment practice for your boiler(s). The general formula for showing the savings associated with optimized boiler combustion efficiency is as follows:

Cost Savings = Fuel Consumption x (1- E1/E2) x Steam Cost

…where E1 is the existing combustion efficiency percentage and E2 is the optimized combustion efficiency percentage. A sample calculation can be found on the BestPractices steam tip sheet entitled *Improve Your Boiler's Combustion Efficiency* (see sidebar for website and contact information).

Safety Issues in Fossil Utility and Industrial Steam Systems

Otakar Jonas, Ph.D., P.E., Jonas, Inc.

This report presents results of recent surveys of safety issues in the fossil utility and industrial steam systems. The boiler problem statistics are from the recent publications by the National Board [1, 2] and the problems with other components are summarized, based on our experience.

The U.S. National Board of Boiler and Pressure Vessel Inspectors reports that 296 power plant boiler-related accidents (including 56 injuries and seven deaths) occurred in 2001 [1]. Over a ten-year period (1992 – 2001), there was a combined total of 23,338 accidents, including 127 fatalities and 720 injuries, reported for all power boilers, water and steam heating boilers, and unfired pressure vessels. The highest number of accidents occurred in 2000 (2,334) and the lowest number (2,011) occurred in 1998. However, the greatest number of both fatalities and injuries occurred in 1999. The total number of deaths increased 40 percent during the time period from 1997 to 2001 as compared to 1992 to 1996 [2].

While the numbers may fluctuate each year, one measure of how the industry is faring can be found in the injury-per-accident ratio. Since 1992, this ratio has ranged from one injury for every 99 accidents in 2000 (the safest year) to one injury for every 19 accidents in 1999 (the most dangerous). The average ratio of injuries to accidents from 1992 to 2001 is one injury for every 32 accidents [2].

Of the 23,338 incidents reported to the National Board from 1992 to 2001, 83 percent were a direct result of human oversight or lack of knowledge (low water condition, improper installation, improper repair, operator error, or poor maintenance). Human oversight and lack of knowledge were responsible for 69 percent of the injuries and 60 percent of the recorded deaths [2].

Table 1 summarizes all of the accidents reported to the National Board in 2001 for several types of pressure vessels [1] and Table 2 gives details on the causes of the power boiler incidents. These figures underscore the importance of safety issues in fossil utility and industrial steam cycles as well as addressing damage mechanisms such as fatigue and corrosion, furnace explosions, fire hazards, handling coal and other fuels, electrical systems, lifting, transportation, and human errors.

What makes a damage mechanism a safety issue is a combination of an undetected slow-acting damage mechanism with a critical load (stress or stress intensity) that leads to a **break before leak**, a **break before vibration**, or some other warning. The problems considered in this paper can be characterized as low frequency, high impact events. Except for the deaerator weld corrosion fatigue cracking, for which root causes are not known, the problems are well understood and the engineering solutions and inspection and monitoring methods are available [3 to 17]. It is mostly a question of the application of this knowledge.

Table 1: Summary of accidents occurring in 2001 for various types of pressure vessels [1]

Type of Vessel	Accidents	Injuries	Fatalities
Power Boilers	296	56	7
Heating Boilers: Steam	1091	0	1
Heating Boilers: Water (includes hot water supply)	631	10	0
Unfired Pressure Vessels	201	18	4
Totals:	2219	84	12

Note: National Board survey based on a 75% response rate for National Board jurisdictional authorities and a 41% response rate from authorized inspection agencies. The total number of surveys mailed was 89, with a 64% response rate overall.

Table 2: Summary of incidents occurring in power boilers in 2001 [1]

Cause of Incident	Accidents	Injuries	Deaths
Safety Valve	4	0	0
Low-Water Condition	161	3	0
Limit Controls	8	0	0
Improper Installation	2	0	0
Improper Repair	1	0	0
Faulty Design or Fabrication	2	0	0
Operator Error or Poor Maintenance	82	50	7
Burner Failure	29	2	0
Unknown/Under Investigation	7	1	0
Subtotal	296	56	7

Table 3 lists critical steam cycle components, their damage mechanisms, and influences. It also gives information on the experience with destructive failures and their dollar impact [18, 19].

Weaknesses in the Safety Control

An example of good safety control is the nuclear power industry where there have been extensive efforts in cycle and component design, development of material properties, component testing, field monitoring, and information exchange. Several organizations, including the Nuclear Regulatory Commission, Institute for Nuclear Power Operation, and Electric Power Research Institute, helped to achieve the current state of nuclear safety.

Such extensive research and organizational support does not exist for the fossil utility and industrial steam cycles. Based on our experience with root cause and failure analysis, the following weaknesses in the industry's handling of the safety issues can be identified:

- Lack of knowledge and/or its application by designers, operators, and inspectors; particularly in industrial steam systems
- Only artificial determination of the root causes. An estimated 40% of the root causes are not correctly determined
- Missing material data, particularly on creep – fatigue and fatigue – corrosion interactions
- Poor understanding of the effects of water and steam chemistry and operation of equipment (cycling, transients, etc.) by investigators and operators

Examples of the deficiencies include a lack of information exchange on safety issues in industrial systems, unknown root causes of deaerator weld cracking, insufficient inspection requirements (only visual inspection of some critical piping, etc.), unknown fundamental mechanisms for fatigue, corrosion fatigue, and stress corrosion.

Recommendations

1. Equipment operators, inspectors, insurance companies, and designers should all address the safety issues.

2. The most effective safety control improvement would be through a similar system used in nuclear safety. A distinguished organization such as ASME and API should assume the responsibility.

3. An effective approach to achieve safety in a steam system includes training and a safety or condition assessment audit (see www.mindspring.com/~jonasinc/condition_assessment.htm).

Table 3: Critical steam components, their damage mechanisms, and influences

Component[1]	Damage Mechanism[2]	Major Influences[3]	Destructive Failures[4]	$ Impact[5]
Steam Piping [6 to 8]	Creep	Welds, temperature, time	Yes	10^7
	LCF, LCCF	Temperature changes		
	Carbon steel graphitization	Temperature and time	Yes	
Drums and Headers [6 to 8]	LCF, LCCF, SCC	Temperature cycling, design, water chemistry	No	10^7
Boiler Tubes [10]	LCCF (20 others)	Water chemistry, cycling, heat flux, etc.	Yes	10^6
Feedwater and Wet Steam Piping [9, 14 to 16]	FAC	Design, water chemistry	Yes	10^7
	Cavitation	Design, operation	Yes	
	SCC	Residual stress, chemistry	No	
	CF, LCCF	Weld quality, water chemistry, temperature changes	No	
Deaerator, Flash Tank, Hot Water and Steam Vessels - Welds [9, 17]	CF, SCC	Design (water piston), residual welding stress, operation, water chemistry	Yes	10^7
LP Turbine Roters and Disks [9, 11 to 13]	SCC	Design stresses, temperature^n, high-strength steel, steam chemistry	Yes	10^7
	CF	Steam chemistry, design, vibration	No	
LP Turbine Blades [9, 11 to 13]	CF SCC	Steam chemistry, design vibration, pitting, erosion, high-strength steel	No	10^6
HP/IP Turbine Rotors [8, 11 to 13]	LCF	Cycling, inclusions, fatigue design	Yes	10^7
Turbine [11 to 13]	Destructive Overspeed	Steam chemistry (boiler carryover), sticking valves	Yes	10^7 - 10^8
Turbine [11 to 13]	Rubbing	Steam chemistry, deposits, thrust bearing, expansion	Yes	10^7

1. Numbers in [ ] are References
2. CF - Corrosion Fatigue, LCF - Low Cycle Fatigue, LCCF - Low Cycle Corrosion Fatigue, SCC - Stress Corrosion Cracking, FAC - Flow-Accelerated Corrosion
3. Age influences the degree of damage for all issues except the last two
4. At least one destructive failure during the last 30 years
5. Lost production and repairs per one event. The cost of lost production is typically much higher than the loss from repairs with a ratio up to 10:1

4. A "Safety Expert System"—a software package, which could be customized for each steam cycle, should be developed.

5. ASME Boiler and Pressure Vessel Code sections dealing with boiler and piping inspections and defect evaluations need to be updated and more specific guidance for NDT and fitness for service evaluations should be provided.

References

1. *2001 National Board Incident Report*. U.S. National Board of Boiler and Pressure Vessel Inspectors.
2. "The Numbers are in … Ten Years of Incident Reports Underscore Human Error as Primary Cause of Accidents." *National Board Bulletin*. Summer 2002.
3. G. Celedonia, et al. "Make Safety Performance Part of 'Business as Usual'." *Power*, January/February 2001.
4. *Fitness for Service*. API Recommended Practice 579, January 2000.

5. *Handbook of Loss Prevention*. Allianz Versicherungs-AG, Berlin/Munchen 1978.
6. *Corrosion in Power Generating Equipment*. Editors Markus O. Speidel and Andrejs Atrens. Plenum Press, New York, 1984.
7. *Fatigue and Fracture, Volume 19*. ASM Handbook, ASM International, Materials Park, OH, 1996.
8. R. Viswanathan. *Damage Mechanisms and Life Assessment of High-Temperature Components*. ASM International, Metals Park, OH, 1989.
9. *Low Temperature Corrosion Problems in Fossil Power Plants – State of Knowledge*. EPRI, Palo Alto, CA. To be published.
10. B. Dooley and W. McNaughton. *Boiler Tube Failures: Theory and Practice, Vol. 2: Water-Touched Tubes*. Electric Power Research Institute, Palo Alto, CA, 1996.
11. T. McCloskey, R. Dooley, and W. McNaughton. *Turbine Steam Path Damage: Theory and Practice, Vol. 2: Damage Mechanisms*. Electric Power Research Institute, Palo Alto, CA, 1999.
12. O. Jonas. "Corrosion and Deposition Problems in Steam Cycle." *Power Station Chemistry 2000 Conference*. May 15-16, Queensland, Australia.
13. O. Jonas and B. Dooley. "Major Turbine Problems Related to Steam Chemistry: R&D, Root Causes, and Solutions." Paper presented at 5th International Conference on Cycle Chemistry in Fossil Plants, EPRI, Charlotte, NC, June 10-12, 1997.
14. B. Chexal, et al. *Flow-Accelerated Corrosion in Power Plants*. Electric Power Research Institute, Palo Alto, CA, 1996. TR-106611.
15. O. Jonas. "Alert: Erosion-Corrosion of Feedwater and Wet Steam Piping." *Power*, February 1996.
16. O. Jonas. "Erosion-Corrosion of PWR Feedwater Piping - Survey of Experience, Design, Water Chemistry, and Materials." *Report for U.S. Nuclear Regulatory Commission*, NUREG/CR-5149, ANL-88-23, March 1988.
17. O. Jonas. "Deaerators: An Overview of Design, Operation, Experience, and R&D." *Proc. of the American Power Conference*, Vol. 49, A. 979, Ill. Institute of Technology, 1987.
18. *Cost of Corrosion in the Electric Power Industry*. EPRI. Palo Alto, CA. October 2001. Report 1004662.
19. B. Syrett, et al. "Cost of Corrosion in the Electric Power Industry." *Materials Performance*. Vol. 41, No. 3. March 2002.

The Human Side of Energy Efficiency: The Value of Training

Rachel Madan, Alliance to Save Energy

When pursuing energy-efficiency projects, what is the best way to proceed? It is fairly easy to demonstrate payback times for technical solutions such as installing heat economizers, back-pressure turbines, or efficient motors. Is this technical overhaul sufficient? Perhaps changes in the management structure would be a better approach? The answer is that neither is effective without the other. Unfortunately, many plant managers concentrate their efforts solely on technical improvements, ignoring the tremendous savings that can arise through low-risk, low-tech solutions such as training for proper maintenance and operation.

Plant managers may concentrate their efforts on technical innovations because these innovations have greatly improved the energy-efficiency potential of industrial processes since the 1973 oil embargo. In fact, energy intensity (energy use per unit of production) in the manufacturing sector fell steadily from 1973 to 1985, when it stabilized. Reductions in energy intensity increased again in 1993. Even so, facility managers cannot look to technical solutions for all energy use problems. In fact, many problems stem from lack of training related to system optimization or ineffective training programs. Establishing an effective, low-cost, low-tech training and maintenance program within a plant can prevent the seemingly endless cycle of fighting recurring problems. By devoting resources to solving the problems at hand, management investments in training can have a fast payback and lasting results.

Unfortunately, the value of training, not only to improving energy efficiency, but also to the bottom line, is often greatly underestimated. Training is often perceived as a cost, not an investment. The value of training beyond its contribution to plant safety is often undervalued. Investing in a training program will minimize costs, increase profit, and improve productivity and reliability. In fact, training is one of the most valuable investments a company can make. A study conducted by the American Society for Training and Development found that training investments across all sectors could yield favorable financial returns for firms and their investors. This study found that an increase of $680 in a firm's training expenditure per employee generates, on average, a six percentage point improvement in TSR (total shareholder return) in the following year, even after controlling for many other important factors.

Although there exists a general awareness of the benefits of training to energy efficiency, this awareness does not seem to break through the barriers managers face when trying to implement training programs. Why is this so? In many companies, energy efficiency is simply not a great concern of those controlling the funds for training. One of the largest barriers to implementing training is the underestimation of its importance, both by management and staff alike. Although training will greatly help to improve the energy efficiency of a plant, perhaps a better way to express its value is to stress the other benefits of training: safety, reliability, productivity, and the financial bottom line. All of these cost-saving measures will help to curb energy usage, even though their benefits go far beyond the immediate benefits of energy efficiency.

Perhaps the most obvious and important benefit of training is improving the safety record of a plant. For example, Weirton Steel Corp. undertook a series of training initiatives beginning in 1998, including safety-awareness training, hands-on workstation training, and certifying all plant supervisors in OSHA's General Industry Standards. As a result, recordable incidents fell 63 percent from 1997 to 2000. In addition, other intangible factors, such as attitude, improved. In 1997, only 15 percent of Weirton Steel Corp. employees surveyed believed that their own actions could protect their co-workers. In 2000, 60 percent believed this to be true.

In addition, a properly trained staff is a large part of maintaining reliable equipment, which also increases productivity. For example, in 1990, U.S. Steel embarked on a comprehensive predictive maintenance program to improve maintenance practices and lower maintenance costs. The program focused on employee involvement, training, and team activity. Misalignments of rotating equipment dropped from 15 percent in 1990 to only one percent in 1996. Success such as this led to the 1993 and 1995 National Maintenance Excellence Award for maintenance and equipment reliability.

Such an increase in reliability will no doubt lead to improvements in productivity. An example of this is the predictive maintenance program at the Fletcher Challenge Canada's Crofton (British Columbia) pulp mill. The Crofton mill embarked on a preventative maintenance program by creating a full-time maintenance systems specialist position and a team of hourly employees to build the preventative maintenance process. This team was trained through both classroom and field sessions. The sessions covered the tools and techniques necessary to perform the inspections, as well as *why* the inspections were necessary and what the benefits were from doing them. In just two years, the team met its goal of a 30 percent reduction in lost production due to breakdowns from the base year, translating into $3.54 million (Canadian) per year.

Lastly, training greatly impacts the bottom line. For instance, ICI, a British chemicals company, invested £100,000 (1992 prices) for direct training costs, including training, employment of a full-time energy manager, and revenue expenditure on repairs and minor improvements. The result was a savings of over £500,000 (1992 prices) per year, an astounding ten-week payback period. In another example, a recently trained Hallmark Canada employee used his knowledge to develop an energy efficiency project resulting in $32,000 (Canadian) savings per year—a 1.6 year payback for the cost of the project.

Obviously, there are many benefits to training – increased safety, reliability, productivity, and cost-savings for companies. Unfortunately, the message of training for energy efficiency is often overlooked when implementing a training program. It is important to extrapolate the benefits of any energy efficiency improvements to other areas of the company. For instance, training staff to implement a steam trap maintenance program will increase the efficiency of a steam system—but more importantly, it will save the company money through increased reliability and productivity of the system.

In order to implement a successful training program, managers must be committed, proactive, and supportive, both attitudinally and financially. The rewards are great for this kind of support. Successful training reduces accidents, improves reliability, and improves efficiency, productivity, and the bottom line. Training must be treated as a fundamental requirement of comprehensive management.

Preliminary Results from the Industrial Steam Market Assessment

Glenn P. McGrath, P.E., CEM, Resource Dynamics
Dr. Anthony L. Wright, Oak Ridge National Laboratory

ABSTRACT

This paper discusses fuel use and potential energy savings in the steam systems of three steam intensive industries: pulp and paper, chemical manufacturing, and petroleum refining. To determine the energy consumption to generate steam in these industries, a combined top-down and bottom-up approach was used. The top-down approach relied on data from the Manufacturing Consumption of Energy Survey (MECS) while the bottom-up approach assessed energy intensities of key processes and/or products in each industry. The results of the top-down approach indicate that to generate steam the pulp and paper industry used 2,221 trillion Btu, the chemical manufacturing industry used 1,548 trillion Btu, and the petroleum refining industry used 1,676 trillion Btu. The results of the bottom-up assessments indicate that these energy use estimates are reasonable. To determine the fuel savings available to each industry from steam system improvements, expert judgment was elicited. Preliminary results from the effort to determine potential steam system fuel savings are discussed.

INTRODUCTION

The U.S. Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy (EERE) BestPractices efforts aim to assist U.S. industry in adopting near-term energy-efficient technologies and practices through voluntary technical-assistance programs on improved system efficiency. There are nine industry groups—designated Industries of the Future (IOFs)—that are the focus of the OIT efforts. These IOFs include Agriculture, Aluminum, Chemicals, Forest Products, Glass, Metal Casting, Mining, Petroleum, and Steel. BestPractice efforts cover motor-driven systems such as pumps and fans, compressed air, steam, and process heating systems.

The overall goal of the BestPractices Steam effort is to assist steam users in adopting a systems approach to designing, installing, and operating boilers, distribution systems, and steam applications. In June 2000, Resource Dynamics Corp., under contract with the Oak Ridge National Laboratory (ORNL) with funding from DOE-OIT, initiated an Industrial Steam System Market Assessment. Two of the major goals of this Steam System Market Assessment effort were: 1) to develop baseline data on steam generation and use by the pulp and paper, petroleum refining, and chemical manufacturing industries; and 2) to develop baseline data on potential opportunities available for improving the energy efficiency of industrial steam systems for these three industries. This paper presents preliminary results from the steam market assessment effort.

STEAM GENERATION, USE IN THE PULP AND PAPER, PETROLEUM REFINING, AND CHEMICAL MANUFACTURING INDUSTRIES

Steam Generation

To estimate the amount of fuel used to generate steam for the pulp and paper, petroleum refining, and chemical manufacturing industries, we assessed data from Manufacturing Consumption of Energy Survey 1994 (MECS)[1]. MECS provides the most comprehensive data for fuel use in these industries, reporting fuel use data at the 4-digit SIC level. However, many of the data are missing or are omitted due to several possible reasons, including disclosure of competitive information, insufficient statistical confidence, and inadequate representation of data. Fortunately, in many instances, this data can be inferred using other tables and/or applying assumptions about industry processes. We inferred this missing data, then assessed how much fuel is used to generate steam.

MECS reports fuel use in three principal categories: “Indirect Uses—Boiler Fuel”, “End use not reported” (EUNR), and “Conventional electricity generation.” EUNR data primarily consist of “Other” fuels, which account for energy that is not included in the major energy source categories. Common examples of other fuel are coke, refinery gas, and wood chips. We allocated the fuel use data from these principal categories based on process characteristics of the pulp and paper, chemical manufacturing, and petroleum refining industries. For example, for the pulp and paper industry, EUNR data is allocated entirely to boiler fuels due to the steam intensive nature of the thermal processes in that industry. In the chemical industry, many production processes are direct-fired. For example, ethylene and propylene production require large amounts of fuel to fir pyrolysis furnaces. Similarly, in the petroleum industry, there are several processes that use waste fuels both to generate steam and to provide direct heating for other processes. To allocate the appropriate amount of "Other" fuel to steam generation for the chemical manufacturing and petroleum refining industries, we determined the amount of fuel used in direct-fired applications in these industries [2]. We then subtracted this fuel use from the "Other" fuel data.

Another component of fuel use that is included in the industry total for generating steam is conventional electricity generation. MECS provides data that indicate the amount of all on-site electric generation that is cogenerated for each industry. Combining this data with the assumption that the energy available to generate steam is 65 percent of the fuel used to generate electricity, provides an estimate of the fuel allocated to steam from "Conventional Electricity Generation." The results for these three fuel components are shown in Table 1.

To convert the fuel energy data into steam usage, estimates of the conversion efficiencies are required. The average boiler efficiencies for each industry were determined based on the distribution of fuel types [3] as indicated by MECS. For example, the combustion efficiency of boilers that use fuels such as bark and black liquor was estimated at 65 percent, while the combustion efficiency of boilers that burn coal was estimated at 81 percent. Table 2 provides the result of this conversion for these three industries.

Pulp and Paper Industry Steam Use

Estimates of the process steam requirements of the pulp and paper industry are determined by a bottom up approach that evaluates the manufacturing processes. The basis for this approach uses the typical energy requirements for integrated facilities. Integrated facilities include all three major process steps—preparation, pulping, and paper or paperboard manufacturing—that are required to manufacture finished paper and paperboard products from logs. Preparation is the process of converting logs into wood chips that are small enough to be sent into the pulping process.

Table 1: Energy Consumed to Generate Steam by Industry

	SIC	Indirect Uses - Boiler Fuel	End Use Not Reported	Conventional Electricity Generation	Total
Pulp and Paper	**26**	**849**	**1,351**	**20**	**2,221**
Pulp Mills	2611	40	191	0	231
Paper Mills	2621	459	611	15	1,085
Paperboard Mills	2631	288	533	6	827
Other Pulp and Paper Segments		62	16	0	78
Chemicals	**28**	**1,229**	**184**	**127**	**1,540**
Alkalies and Chlorine	2812	51	30	0	81
Inorganic Pigments	2816	10	10	0	20
Inorganic Chemicals	2819	101	23	1	126
Plastics and Resins	2821	137	50	0	187
Synthetic Rubber	2822	23	9	0	32
Organic Fibers, Noncellulosic	2824	72	8	0	80
Cyclic Crudes and Intermediates	2865	81	27	3	111
Organic Chemicals	2869	389	11	88	488
Nitrogenous Fertilizers	2873	72	13	1	86
Other Chemical Segments		293	3	34	330
Petroleum	**29**	**304**	**1,323**	**47**	**1,675**
Petroleum Refining	2911	295	1,313	47	1,655
Other Petroleum Refining Segments		9	11	0	20

Units are trillion Btus

Table 2: Estimated Steam Generation by Industry

	SIC	Indirect Uses - Boiler Fuel	End Use Not Reported	Conventional Electricity Generation	Total
Pulp and Paper	**26**	**527,857**	**840,094**	**14,153**	**1,382,103**
Pulp Mills	2611	23,617	112,891	0	136,509
Paper Mills	2621	278,992	371,382	10,400	660,774
Paperboard Mills	2631	177,308	328,143	4,070	509,520
Other Pulp and Paper Segments		47,939	27,678	0	75,301
Chemicals	**28**	**841,277**	**125,952**	**88,348**	**1,055,577**
Alkalies and Chlorine	2812	34,396	20,233	0	54,629
Inorganic Pigments	2816	6,870	6,938	0	13,808
Inorganic Chemicals	2819	69,892	16,054	904	86,851
Plastics and Resins	2821	92,505	33,761	45	126,311
Synthetic Rubber	2822	15,726	6,154	0	21,880
Organic Fibers, Noncellulosic	2824	50,450	5,707	0	56,157
Cyclic Crudes and Intermediates	2865	55,643	18,548	1,809	76,000
Organic Chemicals	2869	257,687	7,287	61,217	326,191
Nitrogenous Fertilizers	2873	50,895	9,189	904	60,988
Other Chemical Segments		207,213	2,081	23,468	232,762
Petroleum	**29**	**207,052**	**901,063**	**32,696**	**1,140,811**
Petroleum Refining	2911	200,857	893,709	32,696	1,127,262
Other Petroleum Refining Segments		6,196	7,353	0	13,549

Units are million lbs. of steam

Pulping is the process of obtaining fibers from the wood. Paper or paperboard manufacturing forms these fibers into final products. Table 3 shows the range of thermal and electric energy use for integrated plants [3].

Most paper and paperboard products can be grouped into 14 categories. Production processes can be allocated to these product categories. Assigning production processes—and the energy usage associated with them—to these product classes provides one way of estimating thermal energy use for each product class [4].

In pulp and paper manufacturing, thermal energy is provided almost entirely by steam. Consequently, multiplying the thermal energy required for each ton of product by the tons of product produced determines the total amount of steam required by the industry. To determine the amount of fuel needed to generate this steam, a conversion factor must be applied. This conversion accounts for losses in burning the fuel, generating the steam, and distributing it to the end uses. For this report, a fuel to steam conversion efficiency of 75 percent was assumed. As indicated in Table 4, the total thermal energy requirement for the

Table 3: Thermal and Electric Energy Use for Integrated Pulp and Paper Plants

Process Energy for Integrated Mills	Thermal		Electrical		Total	
	Min	Max	Min	Max	Min	Max
Chemical (Kraft and Sulfite)	16,000	33,000	2,400	5,500	18,400	38,500
Mechanical	8,000	25,000	6,500	17,200	14,500	42,000
Sulfite semi-chemical	17,000	35,000	4,100	6,800	21,000	41,800
Chemi-thermal mechanical	9,000	25,000	7,500	16,400	16,500	41,400

Thousand Btus/ton

Table 4: Pulp and Paper Thermal Energy Requirements by Product Type

Energy Consumption by Product		Production	Thermal Energy Consumption		
		(Thousand short tons)	(Trillion Btus)		
	Product		Min	Max	Ave
Paper Products	Newsprint	6,984	54	173	113
	Groundwood printing & converting	1,915	15	47	31
	Coated paper	8,804	141	291	216
	Uncoated free sheets	13,304	213	439	326
	Bleached bristols	1,383	22	46	34
	Cotton fiber	159	3	5	4
	Thin papers	149	2	5	4
	Tissue	6,098	98	201	149
	Unbleached kraft	2,308	30	69	50
	Bleached, specialty packaging	2,417	39	80	59
Paper Board	Unbleached kraft paperboard	22,468	292	674	483
	Solid bleached paperboard	5,029	80	166	123
	Semichemical paperboard	5,943	101	208	155
	Recycled paperboard	12,283	123	332	227
		Total	**1,212**	**2,735**	**1,974**

pulp and paper industry was 1,980 trillion Btu. Applying a 75 percent conversion factor results in an estimated boiler fuel use of 2,640 (= 1,980/0.75) trillion Btu.

MECS indicates that the fuel used to generate steam in the pulp and paper industry was 2,221 trillion Btu (refer to Table 1), which is about 16 percent less than the 2,640 trillion Btu estimate. Although many assumptions are built into this model, the relative agreement between these data indicates that these assumptions are reasonable.

Petroleum Refining Industry Steam Use

The petroleum refining industry uses energy to convert crude oil into many different products, some of which are used directly by consumers, while others are feedstocks for other industries. Petroleum refining uses a series of processes to produce these products. Combining the energy required by each process and the amount of product that was produced by each process provides an estimate of the total amount of energy used by the industry. Additionally, the component energy types, including direct-fired, electric, and steam, can be disaggregated from the energy data for each refining process [2]. This allocation allows the total steam use within the industry to be evaluated against the amount of fuel used to generate steam as indicated by MECS.

Table 5 describes the average energy requirements of the key refining processes by technology and combines production estimates to calculate overall industry energy use [5,6]. The total steam energy use is estimated to be 1,071 trillion Btu. If the steam system efficiency is 75 percent, then the fuel use that corresponds to this energy estimate is 1,428 trillion Btu.

To evaluate the accuracy of the "energy use by process" approach, recall that the MECS estimate for the amount of fuel used to generate steam in the petroleum refining industry was 1,676 trillion Btu. The resulting difference is 248 trillion Btu or about 15 percent. In relative terms the "energy use by process" approach indicates that steam represents 46 percent (= 1,071/2,333) of the total energy use, while MECS indicates that the fuel used to generate steam represents about 53 percent of the industry fuel use.

Table 5: Energy Use Requirements of Common Refinery Processes

			Energy Use by Technology (Trillion Btus)			
Process	Average Unit Energy Use (Thousand Btus/bbl)	Production (Thousand bbls/day)	Direct Fired	Electric	Steam	Total
Atmospheric Distillation	114	14,584	383	12.3	246.1	641.7
Vacuum Distillation	92	6,433	113	2.8	123.3	238.8
Visbreaking	87	65	3	0.7	(1.3)	2.1
Coking Operations	170	1,771	110	14.1	(9.4)	115.1
Fluid Catalytic Cracking	100	5,051	166	23.4	114.4	189.8
Catalytic Hydrocracking	240	1,261	62	18.2	33.6	113.9
Catalytic Hydrotreating	120	7,912	202	54.6	212.0	468.7
Catalytic Reforming	284	3,692	243	13.5	117.2	373.2
Alkylation	375	1,157	-	10.9	139.5	150.4
Isomerization	-	-			-	-
Isobutane	359	101	-	0.4	12.4	12.8
Isopentane/Isohexane	175	434	-	0.9	25.9	26.8
		Total	**1,283**	**152**	**1,014**	**2,333**

Chemical Manufacturing Industry Steam Use

The chemical manufacturing industry uses energy to manufacture over 70,000 products for consumer and industrial markets. Although the chemical industry manufactures a wide range of products, a relatively small number of them account for most of the industry energy use. As a result, evaluating the processes for manufacturing these high energy-use chemical products can provide a reasonable assessment of how much energy, specifically steam energy, is used [7,8].

As shown in Table 6, there are 20 chemical products whose process steam energy requirements account for 824 trillion Btu of steam.

This study used a 75 percent conversion efficiency to account for losses in converting fuel to thermal energy, generating steam and delivering it to the end uses. This conversion factor produces a fuel use estimate of 1,099 trillion Btu. Since MECS indicates that the chemical industry used about 3,273 trillion Btu of energy [2], of which steam energy accounts for roughly 1,548 trillion Btu, evaluating the process energy requirements of these 20 chemical products accounts for about 71 percent of the total chemical manufacturing industry steam use.

Developing Baseline Steam Performance Improvement Opportunity Data

To determine the potential savings from improving steam system efficiency and performance, we determined that expert elicitation would be the most effective approach. Experts with experience in the steam systems at multiple industrial facilities are able to provide data that is representative of industry conditions. An optional approach is to survey a representative sample of industrial facilities in the subject industries. However, steam systems are often very expansive. Gathering enough data to assess each system adequately—even in a representative sample of facilities—would be prohibitively costly.

Effective expert elicitation requires asking the right people the right questions. To find the right people, we sought a set of qualified experts. These contacts were made through:

- The BestPractices Steam program,
- Referrals by other industry stakeholders, and
- Industry research.

Table 6: Steam Energy to Make Selected Chemical Products

Chemical	SIC	Production (Million lbs)	Unit Steam Energy (Btu/lb)	Total Steam Energy (Trillion Btu)	Total Energy (Trillion Btu)
Ethylene	2869	44,534	7,695	343	406
Ammonia	2873	15,788	5,062	80	274
Ethylbenzene/Styrene	2865	11,270	15,000	169	190
Polystyrene	2821	7,620	2,123	16	17
Chlorine/Sodium Hydroxide	2812	25,078	2,909	73	197
Ethylene Dichloride/Polyvinyl Chloride	2821	14,818	1,648	24	34
Phenol/Acetone	2865	4,054	7,459	30	32
Benzene, Toluene, and Xylene	2865	28,118	342	10	12
Caprolactum	2824	1,508	9,691	14.6	18
Sodium Carbonate	2812	20,552	2,683	55	79
Polybutadiene Rubber	2822	550	1,584	0.9	10
Styrene Butadiene Rubber	2822	2,497	2,049	5	7
Butyl Rubber	2822	431	638	0.3	7
Cyclohexane	2865	2,108	1,593	3	4
			Totals	**824**	**1,287**

Prospective participants were contacted to determine their level of knowledge and experience in the steam systems of the subject industries. After describing the objectives of this project and assessing the qualifications of the prospective participants, we requested qualified experts to provide responses regarding estimates of steam system energy savings.

To ask the right questions regarding these savings, we developed a list of 30 performance improvement opportunities, which are listed below:

- Minimize Boiler Combustion Loss by Optimizing Excess Air
- Improve Boiler Operating Practices
- Repair or Replace Burner Parts
- Install Feedwater Economizers
- Install Combustion Air Preheaters
- Improve Water Treatment
- Clean Boiler Heat Transfer Surfaces
- Improve Blowdown Practices
- Install Continuous Blowdown Heat Recovery
- Add/Restore Boiler Refractory
- Establish the Correct Vent Rate for Deaerator
- Reduce Steam System Generating Pressure
- Improve Quality of Delivered Steam
- Implement an Effective Steam Trap Maintenance Program
- Ensure Steam System Piping, Valves, Fittings, and Vessels are Well Insulated
- Minimize Vented Steam
- Repair Steam Leaks
- Isolate Steam from Unused Lines
- Improve System Balance
- Improve Plant Wide Testing and Maintenance Practices
- Optimize Steam Use in Pulp and Paper Drying Applications
- Optimize Steam Use in Pulp and Paper Air Heating Applications
- Optimize Steam Use in Pulp and Paper Water Heating Applications
- Optimize Steam Use in Chemical Product Heating Applications
- Optimize Steam Use in Chemical Vacuum Production Applications
- Optimize Steam Use in Petroleum Refining Distillation Applications
- Optimize Steam Use in Petroleum Refining Vacuum Production Applications
- Improved Condensate Recovery
- Use High Pressure Condensate to Generate Low Pressure Steam
- Implement a Combined Heat and Power (Cogeneration) Project

The principal data that are necessary for assessing each improvement opportunity are:

- Fuel savings,
- Percentage of facilities for which each opportunity is feasible,
- Payback period, and
- Reasons for implementing the opportunity. This response provides insight into why the improvement opportunity is usually implemented.

We determined that the best tool to elicit expert knowledge regarding these opportunities was a questionnaire. A questionnaire provides several advantages, including flexibility in devoting time to complete it, allowing research, and permitting write-in comments. Before sending the questionnaire to the experts, it was reviewed by a separate group of industry stakeholders. The questionnaire was reviewed and modified until it met three important objectives:

- Is it user friendly?
- Are the questions unambiguously worded?
- Do the responses gather accurate and representative data?

The questionnaire was sent to 34 people who agreed to participate. Nineteen of the participants returned the questionnaire with useful data. After the questionnaires were returned and the data extracted, several different approaches were considered to statistically evaluate the collected data.

There were also several approaches considered in presenting the data. One method groups the data by industry; another presents combined data for all three industries. Although most of the experts indicated that they have more experience in some industries than others, there was little distinction among the estimates of the fuel savings, feasibility percentages, and paybacks for each industry.

Lower and upper uncertainty values characterize the range of differences among the experts' responses. Lower and upper certainty values of 2.5 and 97.5 percentile respectively were selected. A large difference between the upper and lower uncertainty estimates indicates that there was a wide range among responses of the experts. Conversely, a small difference indicated a relatively close agreement among the experts.

At the time this paper was prepared, the results have not received sufficient industry review to allow presentation of the final data. However, we can note the following, based on evaluation of the results from the experts who participated:

- Estimated fuel savings for the 30 identified performance improvement opportunities ranged from 0.6 percent to 5.2 percent;
- Percent of facilities for which the performance opportunities are feasible ranged from three percent to 31percent; and
- Estimated payback periods for the performance improvement opportunities ranged from three to 36 months.

Conclusions and Future Efforts

Once the full results of this effort have received sufficient industry review, a Steam System Market Assessment report will be prepared. This report will include the detailed results on steam generation and use and steam system performance opportunities available for the pulp and paper, petroleum refining, and chemical manufacturing industries. These results will provide baseline data for the key opportunities available for improving industrial steam system energy efficiency.

Acknowledgements

The authors acknowledge the financial support provided by the DOE EERE for this effort. They also acknowledge the guidance and support of the BestPractices Steam Steering Committee and the BestPractices Steam Technical Subcommittee. Finally, the authors acknowledge the efforts of the experts who provided the data on industrial steam system performance improvement opportunities.

References

1. Manufacturing Consumption of Energy 1994, Energy Information Administration, U. S. Department of Energy, December 1997.
2. 1992 Industrial Process Heat Energy Analysis, Final Report no. GRI 96/0353, Gas Research Institute, September 1996.
3. Scoping Study Pulp and Paper Industry, EPRI, Prepared by Giese & Associates, December 1988.
4. Directory of the Pulp, Paper, and Allied Trades, Lockwood Post, 1996.
5. 1992 Industrial Process Heat Energy Analysis, Final Report no. GRI 96/0353, Gas Research Institute, September 1996.
6. Oil and Gas Journal Online, http://ogj.pennnet.com/home.cfm, U.S. Refineries – State capacities for 1995 – 2000.
7. Energy and Environmental Profile of the U.S. Chemical Industry, U.S. Department of Energy, Office of Industrial Technologies, May 2000.
8. U.S. Chemical Industry Statistical Handbook 1999, Chemical Manufacturers Association, 1999.

Results from the Industrial Assessment Center (IAC) Steam Tool Bechmarking Support Project

Dr. Anthony L. Wright, Oak Ridge National Laboratory
Dr. Kurt Bassett, South Dakota State University
Dr. Herbert Eckerlin, North Carolina State University
Dr. Ahmad Ganji, San Francisco State University
Derek Hengeveld, South Dakota State University
Dr. Richard Jendrucko, University of Tennessee, Knoxville
Dr. Dragoljub Kosanovic, University of Massachusetts, Amherst
Dr. Wayne Turner, Oklahoma State University

Introduction

The U. S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE) BestPractices effort is developing a number of software tools to assist industrial energy users to improve the efficiency of their operations. One of the software tools that have been developed is the "Steam System Scoping Tool." The Steam Scoping Tool is an Excel spreadsheet that can be applied by industrial steam users to: a) evaluate their steam system operations against identified best practices; and b) develop a greater awareness of opportunities to improve their steam systems.

The Steam Scoping Tool was developed by BestPractices Steam (the Best Practices and Technical subcommittee of BestPractices Steam); the tool was initially released in August 2000.

In June 2000, the Industrial Assessment Center (IAC) Steam Tool Benchmarking Support project was started. DOE IACs provide energy, waste, and productivity assessments at no charge to small to mid-sized manufacturers. These assessments help manufacturers maximize energy efficiency, reduce waste, and improve productivity. The assessments are performed by teams of engineering faculty and students from participating universities/IACs across the United States.

The IAC Steam Tool Benchmarking Support project had three main tasks:

Task 1: Compile steam system benchmarking data from past IAC steam assessments;
Task 2: Perform one-day focused steam system assessments to test new steam assessment tools and to develop new steam benchmarking data; and
Task 3: Document the results of the Task 2 efforts.

Six IACs participated in this project:

- University of Massachusetts, Amherst;
- North Carolina State University;
- Oklahoma State University;
- San Francisco State University;
- South Dakota State University; and
- University of Tennessee, Knoxville.

This paper summarizes the results for the key efforts of the project—the results from the 18 steam system assessments, and the results of the evaluations of the Steam System Scoping Tool.

Results from the 18 IAC Steam System Assessments

Each of the six IACs performed three one-day steam system assessments in industrial plants. As part of the effort to perform these assessments, two BestPractices Steam assessment tools were utilized:

a. The Steam System Scoping Tool; and
b. The Steam System Survey Guide. This guide (presently in draft form) has been developed by Dr. Greg Harrell from the University of Tennessee, Knoxville. It is a reference document that provides a technical basis for identifying and assessing many potential steam system improvement opportunities. Although the Survey Guide was provided to the IACs to use as a resource, the main focus of this project was to evaluate the usefulness of the Steam Scoping Tool.

Table 1 lists the industrial plant types for the one-day steam assessments. The IACs obtained annual data on the fuel cost to produce steam for 15 of the assessed plants. These annual fuel bills ranged from about $79,000 to $14,800,000 per year; the average for the 15 plants was about $1,600,000 per year.

The key activities associated with each of the 18 steam assessments were the following:

a. Working with the plant staff to obtain answers to questions in the Steam Scoping Tool;

b. Performing the individual steam assessments;
c. Documenting the results of each of the individual steam assessments in summary reports; and
d. Documenting the results of each of the completed Steam Scoping Tool evaluations.

Individual summary reports were prepared for each of the 18 steam assessments. In addition, completed Steam Scoping Tool spreadsheets for each of the plant assessments were prepared.

Table 1: Plant types for the 18 IAC steam benchmarking support steam assessments

Cheese and Whey Products
Chemicals
Corrugated Containers (2)
Fabric Dying Facility
Frozen Food Producer
Hardwood Mouldings
Industrial Cleaning Compounds and Sanitizers
Inorganic Chemical Intermediates
Pulp and Paper Plants (3)
Redwood Lumber
Rubber Tires
Shopping Cart Manufacturer
Styrofoam Cups
Textiles
Vinyl Flooring

Steam improvement opportunities, cost savings, implementation costs, and anticipated paybacks were identified for each of the 18 steam assessments. Eighty-nine improvement opportunities were identified. Sixty-eight of the identified improvements had yearly savings less than $20,000 per year; 21 of the identified improvements had yearly savings greater than $20,000 per year.

The total identified annual energy savings from these assessments was $2,800,000; the average yearly savings for each of the identified 89 improvements was about $31,500 per year. The total identified implementation cost for the 89 was about $1,600,000; the average overall payback for the 89 improvements was about seven months.

Table 2 shows data for annual fuel costs to produce steam and annual identified savings, as a percent of annual fuel costs, for the 18 steam assessments. For eight of the assessments, annual identified savings were greater than nine percent of the annual fuel costs. The average identified energy savings for the 18 steam assessments was 12.5 percent of the individual plant energy bills.

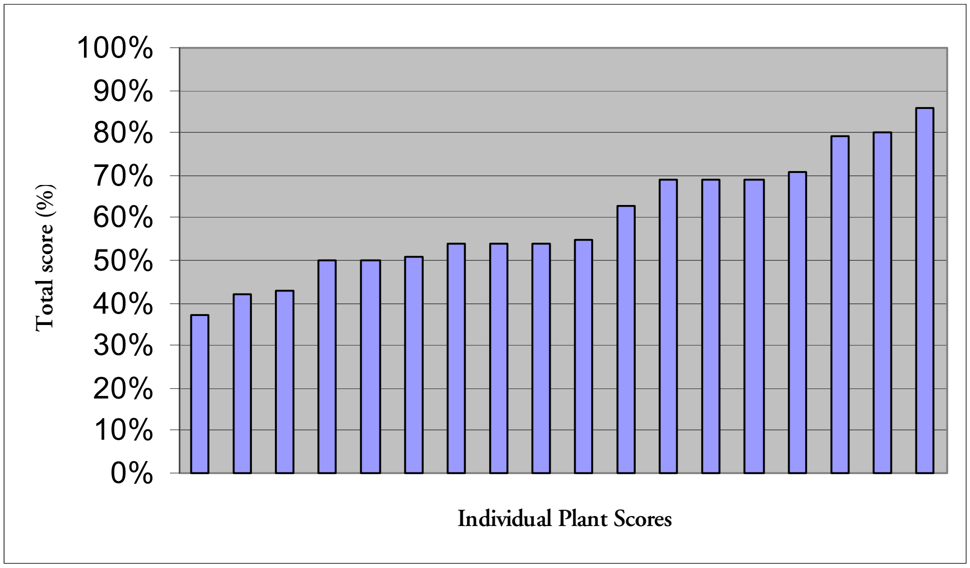
The Steam System Scoping Tool [1] includes seven worksheets associated with identifying steam system improvement opportunities:

a. Introduction;
b. Steam System Basic Data;
c. Steam System Profiling;
d. Steam System Operating Practices – Total Steam System;
e. Steam System Operating Practices – Boiler Plant;
f. Steam System Operating Practices – Distribution, End Use, and Recovery; and
g. Summary Results.

Table 2: Annual fuel cost to make steam and identified annual energy savings as percent of annual steam fuel cost, for the 18 IAC steam assessments.

Plant	Annual Fuel Cost to Produce Steam ($)	Annual Energy Savings as Percent of Annual Steam Fuel Cost
1	$532,940	1.8%
2	$1,579,231	2.6%
3	$157,862	3.4%
4	$261,558	4.3%
5	$661,391	4.6%
6	$173,222	5.6%
7	$14,790,000	6.0%
8	$244,124	6.2%
9	$3,131,040	6.7%
10	$1,224,997	7.0%
11	$1,000,000	9.4%
12	$78,934	10.3%
13	$136,791	13.9%
14	$415,337	15.4%
15	$1,744,680	20.2%
16	$183,889	25.3%
17	$619,016	33.5%
18	$1,456,000	49.2%

Figure 1: Steam System Scoping Tool total scores from IAC steam assessments



A steam user has to answer 26 questions to complete the Steam Scoping Tool; the maximum score that can be achieved in completing the Steam Tool (100 percent) is 340 points. Figure 1 illustrates the individual plant scores achieved for the IAC steam assessments. The individual plant scores ranged from a low of 37.1 percent to a high of 85.9 percent.

Table 3 shows average question responses and standard deviations of question responses for the IAC steam assessments. The results shown in Table 3 illustrate the following:

a. For three of the general areas—Steam System Profiling, Boiler Plant Operating Practices, and Steam Distribution, End Use, and Recovery Operating Practices—the average overall score was about 50 percent. For example, out of 90 points available for Steam System Profiling, the average score for the 18 IAC steam assessments was 44 points;

b. The highest scores were achieved in the area of Steam System Operating Practices—out of 140 available points the average score was 102 points (about 73 percent);

c. The scores varied the most (highest relative standard deviation) for the Steam System Profiling area—for this area, the standard deviation of responses was 28 points out of the available 90 points. This suggests that the plants differed the most in their responses to the Steam Profiling questions.

Steam Scoping Tool Evaluation Results

The IACs prepared an individual summary report for each of the 18 steam system assessments. In addition, each participating IAC prepared a separate report summarizing the overall results of each of their efforts.

A key part of the Steam Scoping Tool evaluation reports was to identify the following types of information:

a. How useful was the Steam Scoping Tool to the plant personnel?
b. How can the Steam Scoping Tool be improved?
c. How can the usefulness of the Steam Scoping Tool to plant personnel be improved?

All of the individual evaluation comments on the Steam Scoping Tool have been reviewed, and many of the suggested improvements will be included in the next release of the Steam Scoping Tool. Some of the key comments made by the IACs are summarized below:

a. A number of the IACs indicated that the question on Options for Reducing Steam Pressure (PR1) needs to be improved. Many facilities will not have the option of reducing pressure using backpressure turbines, and the Steam Tool should reflect this.

SCOPING TOOL AREAS AND QUESTIONS	POSSIBLE SCORE	AVERAGE, IAC RESPONSES	STD. DEVIATION, IAC RESPONSES
1. STEAM SYSTEM PROFILING			
STEAM COSTS			
SC1: Measure Fuel Cost to Generate Steam	10	7	5
SC2: Trend Fuel Cost to Generate Steam	10	6	5
STEAM/PRODUCT BENCHMARKS			
BM1: Measure Steam/Product Benchmarks	10	4	5
BM2: Trend Steam/Product Benchmarks	10	4	5
STEAM SYSTEM MEASUREMENTS			
MS1: Measure/Record Steam System Critical Energy Parameters	30	18	9
MS2: Intensity of Measuring Steam Flows	20	5	7
STEAM SYSTEM PROFILING SCORE	**90**	**44**	**28**
2. STEAM SYSTEM OPERATING PRACTICES			
STEAM TRAP MAINTENANCE			
ST1: Steam Trap Maintenance Practices	40	24	7
WATER TREATMENT PROGRAM			
WT1: Water Treatmen—Ensuring Function	10	8	3
WT2: Cleaning Boiler Fireside/Waterside Deposits	10	9	3
WT3: Measure Boiler TDS, Top/Bottom Blowdown Rates	10	8	4
SYSTEM INSULATION			
IN1: Insulation—Boiler Plant	10	9	3
IN2: Insulation—Distribution/End Use/Recovery	20	14	8
STEAM LEAKS			
LK1: Steam Leaks—How Often	10	6	5
WATER HAMMER			
WH1: Water Hamme—How Often	10	8	3
MAINTAINING EFFECTIVE STEAM SYSTEM OPS.			
MN1: Inspecting Important Steam Plant Equipment	20	16	6
STEAM SYSTEM OPERATING PRACTICES SCORE	**140**	**102**	**18**
3. BOILER PLANT OPERATING PRACTICES			
BOILER EFFICIENCY			
BE1: Measuring Boiler Efficiency -- How Often	10	6	4
BE2: Flue Gas Temperature, O_2 , CO Measurement	15	9	6
BE3: Controlling Boiler Excess Air	10	6	4
HEAT RECOVERY EQUIPMENT			
HR1: Boiler Heat Recovery Equipment	15	6	6
GENERATING DRY STEAM			
DS1: Checking Boiler Steam Quality	10	3	4
BOILER OPERATION			
GB1: Automatic Boiler Blowdown Control	5	3	3
GB2: Frequency of Boiler High/Low Level Alarms	10	9	2
GB3: Frequency of Boiler Steam Pressure Fluctuations	5	4	2
BOILER PLANT OPERATING PRACTICES SCORE	**80**	**45**	**13**
4. STEAM DISTRIBUTION, END USE, RECOVERY OPERATING PRACTICES			
MINIMIZE STEAM FLOW THROUGH PRVs			
PR1: Options for Reducing Steam Pressure	10	5	3
RECOVER AND UTILIZE AVAILABLE CONDENSATE			
CR1: Recovering and Utilizing Available Condensate	10	8	3
USE HIGH-PRESSURE STEAM TO MAKE LOW-PRESSURE CONDENSATE			
FS1: Recovering and Utilizing Available Flash Steam	10	1	3
DISTRIBUTION, END USE, RECOVERY PRACTICES SCORE	**30**	**14**	**6**
TOTAL STEAM SCOPING TOOL SCORE	**340**	**205**	**47**
TOTAL STEAM SCOPING TOOL SCORE (%)		**60%**	**14%**

b. Many of the plant personnel who completed the Steam Scoping Tool felt that it helped them to understand areas where they could improve their steam systems.
c. A number of the plant personnel indicated that they would not have completed the Steam Scoping Tool if they had not been selected to have a free steam system assessment. The responses from the IACs suggest a number of ways to enhance the usefulness of the software tool; for example: 1) provide information on cost savings associated with different improvement opportunities; 2) provide feedback to steam users, after they complete the Tool, providing more details on how improvements can be made; and 3) provide plants with corresponding summary results from other plants to illustrate how their scores compare with other similar plants.
d. A number of the IACs suggested that some measure of comparison be provided on the relative merits of different scoring ranges, e.g. 300-340: excellent, 250-299: very good, etc.
e. Finally, a number of the IACs suggested that improving the overall formatting of the software tool would improve its usefulness.

Summary and Conclusions

In summary, this was a successful project. When the project was started, the Steam System Scoping Tool was about to be released, and there was no measure of how useful the software tool would be for assessing steam systems or where the software tool could be improved. As a result of the project, a number of areas for improving the Tool and the usefulness of the software tool to steam users have been identified.

The results from the 18 steam system assessments will also prove valuable to the overall BestPractices Steam effort.

Acknowledgements

The authors acknowledge the DOE EERE for providing financial support for this effort.

References

1. *The Steam System Scoping Tool: Benchmarking Your Steam System Through Best Practices*, Dr. Anthony L. Wright (Oak Ridge National Laboratory) and Glenn Hahn (Spirax Sarco Inc.), 23rd National Industrial Energy Technology Conference, Houston, TX, May 2001.

ProSteam - A Structured Approach to Steam System Improvement

Alan Eastwood, Linnhoff March Ltd.

Abstract

Optimal operation of site utility systems is becoming an increasingly important part of any successful business strategy as environmental, legislative and commercial pressures grow. A reliable steam model allows a clear understanding of the system and of any operational constraints. It can also be used to determine the true cost of improvement projects, relating any changes in steam demand back to purchased utilities (fuel, power, and make-up water) at the site boundary. Example projects could include improved insulation, better condensate return, increased process integration, new steam turbines or even the installation of gas-turbine based cogeneration. This approach allows sites to develop a staged implementation plan for both operational and capital investment projects in the utility system.

Steam system models can be taken one step further and linked to the site distributed control system (DCS) data to provide real-time balances and improve the operation of the system, providing an inexpensive but very effective optimizer. Such a model ensures that the steam system is set in the optimum manner to react to current utility demands, emissions regulations, equipment availability, fuel and power costs, etc. This optimization approach typically reduces day-to-day utility system operating costs by between 1-5 percent at no capital cost.

Why Build a Steam System Model?

On many operating sites, maybe even the majority of sites, production is king and the steam system is regarded merely as a service that is far less important than the manufacturing processes themselves. Consequently, even companies that invest heavily in process modeling and simulation pay far less attention to the modeling of the steam system and, consequently, do not have the same understanding of the key players, the sensitivities and the interdependencies in this area.

Often, steam is assigned a unit value (dollars per thousand pounds) that serves to cover the perceived costs of operating the utility system when this value is apportioned across the various manufacturing cost centers. This value will, at best, represent an average cost of steam over a period of time and will often be inappropriate or downright misleading if used for evaluating potential projects.

A simple example would be a site that has a very close balance between suppliers and users at the low-pressure steam level. Site management is perhaps considering a new project to reduce the low-pressure steam demand. If the project is evaluated at the accountant's transfer figure of, say, $5 per thousand pounds it may appear that the project will pay back handsomely. In reality, however, the "saved" steam may simply be vented as it has nowhere else to go. The project will therefore save nothing at all and will even lead to the additional cost of lost water and heat in the vent.

A reliable model that reflects what actually happens within the steam system would identify the real cost of the project and avoid this inappropriate capital spend.

The above example is rather simplistic but no less valid for all its simplicity. In real life, the actual cost of low-pressure steam is likely to be variable. It may take on a finite value initially as the first amounts of steam are saved and then, at some point, the above situation applies and the value of low-pressure steam reverts to zero or even a negative value, as described. There may therefore be a specific limit to the amount of steam that can be saved and further investment would be fruitless. It is obviously good to know what this limit is! If a proper understanding of the real marginal steam and power costs is obtained, then the present inefficiencies in the system can be clearly identified and the correct investment decisions taken with confidence.

The true marginal cost of steam at any time and place in the system will depend on the actual path through which the steam passes on its way from generator to consumer. Medium- or low-pressure steam that is simply produced via letdown from the high-pressure boilers will have the same cost as the high-pressure steam. On the other hand, if the medium- or low-pressure steam is exhausted from a steam turbine, then the unit cost of that steam will be less than that of high-pressure steam because of the credit associated with the generation of shaftwork in the turbine.

Also, live steam for process use will have a higher value than the same steam used indirectly in heat exchangers because the latter can obtain credit for the condensate returned to the boilers.

Finally, the time of day is increasingly affecting the cost of steam as power tariffs become increasingly complex following deregulation of the electrical power industry.

Initial reasons for building a model of the steam system could, therefore, be:

- To calculate the real cost of steam under various operational scenarios
- To identify current energy losses
- To accurately evaluate project savings
- To forecast future steam demand versus production
- To identify the critical areas, sensitivities and bottlenecks within the system
- To identify no-cost operational improvements
- To evaluate tariffs and energy contract management
- To target and report emissions
- To form the basis of a consistent investment plan for the site

This paper will go on to show that many other benefits, including the optimization of steam system operation, can be obtained from such a model.

What Type of Model is Available?

Many companies have made a good attempt at spreadsheet-based steam system modeling. Although these in-house models are invariably restricted to mass flow balances and flowrate-based power generation formulae, they represent a significant advance on nothing at all. They have the advantages of spreadsheet operation (flexibility, transparency) but are often limited by the spreadsheet skills of the utility engineer. Also, they cannot simultaneously reconcile mass *and* heat balances such as those required around deaerators. Perhaps their biggest drawback is that they are often only understood by the engineer who built them in the first place.

At the other end of the range is the full-blown process simulator, which is perfectly capable of modeling the utility system. The drawbacks in this case are the cost (large annual license fee) and the lack of transparency of the model. This is particularly important when changes and upgrades are required to be made to the model. The structure of the model may also be too rigid to allow rapid evaluation of a number of possible future scenarios.

A third type of model is that which looks and feels like a spreadsheet but, at the same time, has direct access to the whole range of steam and water properties through an add-in physical properties database. As well as taking advantage of all the benefits of spreadsheet operation, it yields a true simultaneous balance of mass, heat and power in the system. It also offers consistency between different users company-wide, and can be linked easily to the site's data historian for real-time calculations.

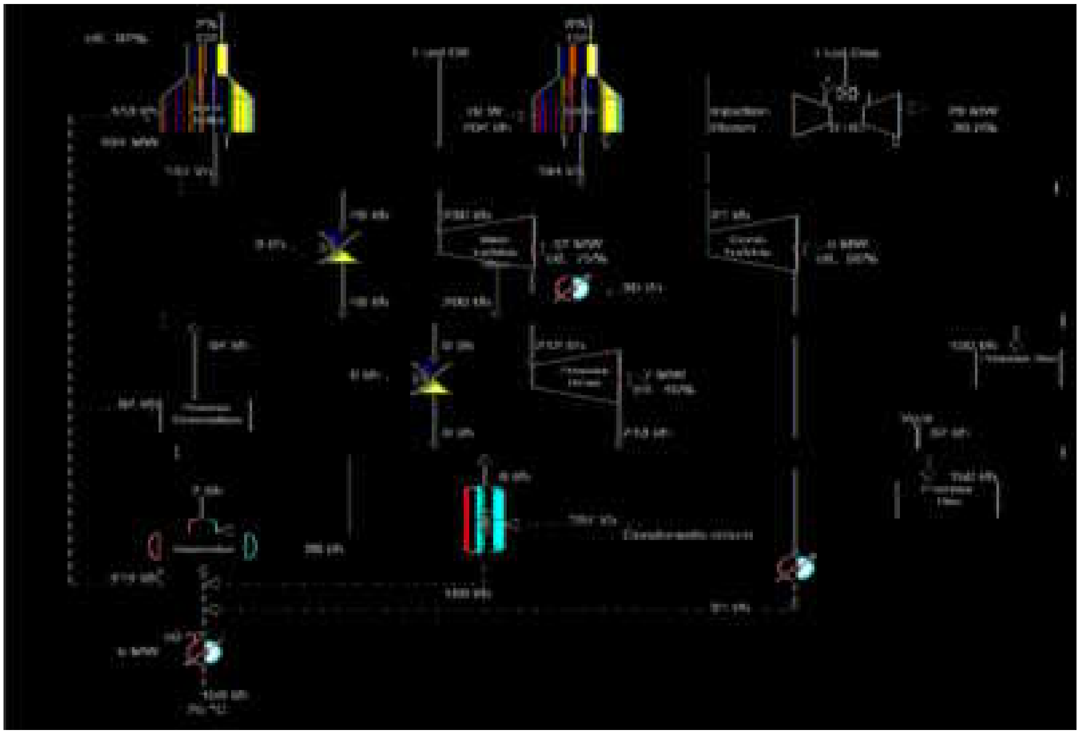
Good software packages in this category should also include drag and drop options for creating the utility flow diagram initially and pre-programmed equipment models to ensure that appropriate and consistent data are inputted and outputted around each equipment item and each header. Figure 1 illustrates a simplified model of a large site steam system including boilers, gas and steam turbines and three pressure levels of steam.

How Can I Use the Model?

There are essentially two distinct types of model or model applications that are relevant to this paper; the planning model described earlier and an optimizer, which is constructed and used somewhat differently to the planning model. These are described below:

1. The planning model allows the engineer to evaluate potential projects, what-if scenarios and future production trends. Typically, this involves building the model with the conventional spreadsheet logic functions, e.g. "IF" statements, to replicate the way in which the plant control system operates. In this way, the model will simulate the present behavior of the system. This type of model can also be linked to the site data historian to produce real-time models and to flag up deviations from an optimum template. Such a model will generally contain two worksheets. The first is a top-down balance based upon plant readings (which is usually more reliable at the high-pressure level) and the second is a bottom-up balance based upon the actual process demands. This allows the actual steam balance at any time (the top-down model) to be compared to an ideal template (bottom-

Figure 1: Typical Site Steam Model



up model) for that mode of process operation/steam demand. Differences can be highlighted and the appropriate action taken by the operator.

2. An optimizer model which will identify the least cost mode of utility plant operation under different scenarios (production rates, power tariffs, etc). This differs from the planning model in that it automatically switches equipment items on and off within the model to arrive at the true optimum. Depending on the number of degrees of freedom in operating the system (alternate drives for rotating equipment, choice of different equipment items, let-downs and vents), the model is capable of saving between 1-5 percent of utility cost at zero capital cost. Simple models can use Microsoft Solver to identify the optimum settings for the system whereas more powerful, advanced solvers are needed for more complex problems. This type of model is often used on-line at the control room level to improve hour-by-hour operation. Equally, it can be used off-line for management to pre-determine how best to operate the utility system under future planned conditions (for example, on a weekly basis tied to anticipated production, time of year and time of day power tariffs).

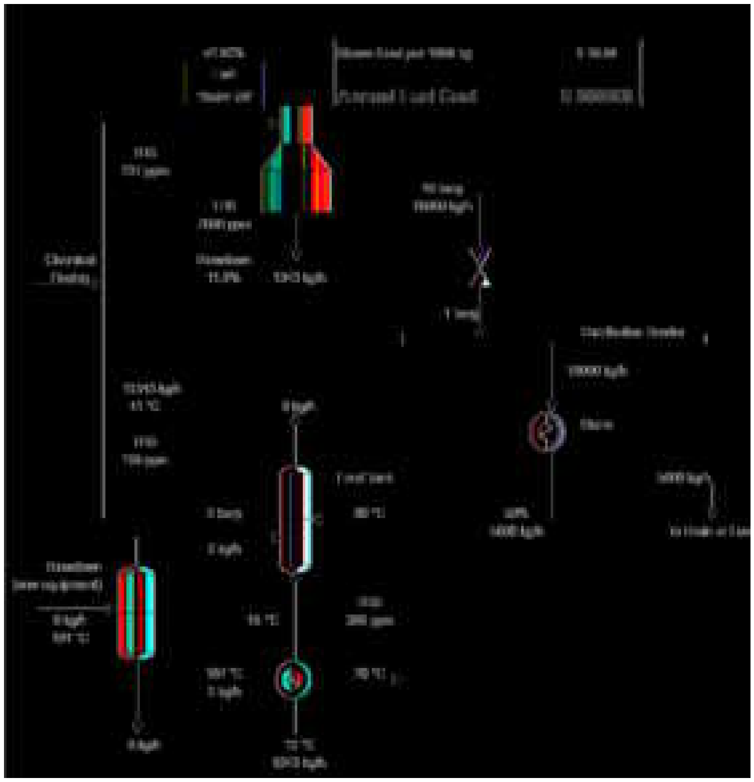
Figure 2 illustrates the first option, for off-line project planning.

This is a simple, single level steam system with several potential projects already incorporated but deactivated in the base case. It indicates that the base case operation costs $600,000 per year in terms of fuel and water. Potential projects that can quickly be investigated with this model include:

- Improved condensate return (from 50-80 percent);
- Increased allowable TDS through continuous blowdown control;
- Blowdown flash steam recovery;
- Boiler blowdown to pre-heat boiler feedwater; and
- Boiler efficiency improvement (from 80- 85 percent).

The model allows any or all of these modifications to be calculated by simply ticking the box alongside the project in the table at the right hand side of the spreadsheet. Figure 3 shows that incorporating ALL of the potential projects will reduce the annual operating cost to $483,900, a saving of $116,100 per year, or almost 20 percent.

Figure 2: Base Case (Existing) Steam Balance



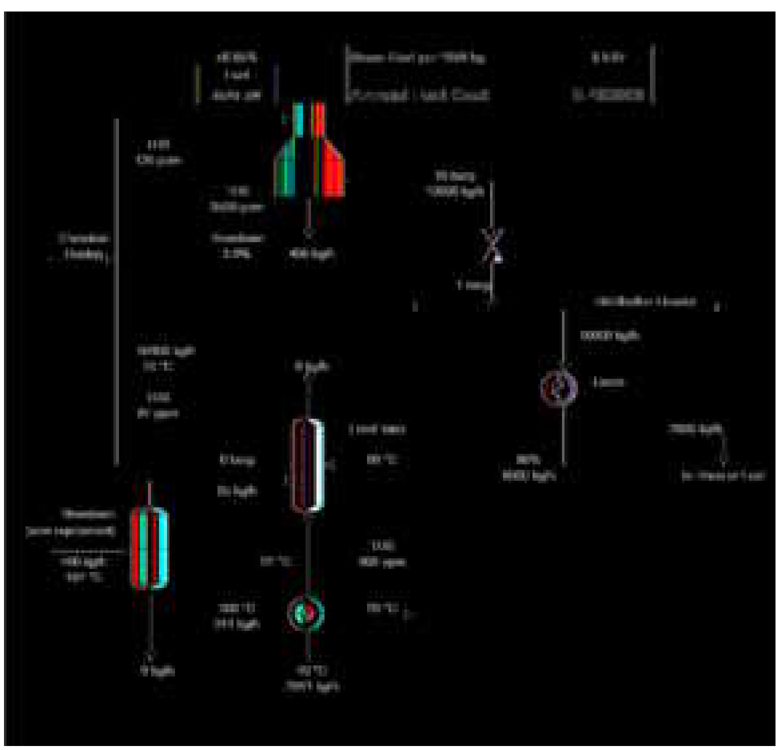
Base Case Parameters

Steam Generation Pressure	10 barg
Header Pressure	1 barg
Steam Demand	10000 kg/h
Boiler Efficiency	80%
Boiler TDS Level	2000 ppm
Condensate Return	50%
Condensate Temperature	80 °C
Make-Up Water Temperature	10 °C
Make-Up TDS Level	300 ppm
Feed Tank Pressure	0 barg
Dosing TDS Increase	69 ppm
Operation	6000 h/y
Fuel Cost	9.47 $/MWh

Potential Improvement Projects

Condensate Return	80%	☐
Allowable TDS	3500 ppm	☐
Blowdown Flash	0 barg	☐
Blowdown HX	10 °C approach	☐
Boiler Efficiency	85%	☐

Figure 3: Steam Balance After Inclusion of Projects



Base Case Parameters

Steam Generation Pressure	10 barg
Header Pressure	1 barg
Steam Demand	10000 kg/h
Boiler Efficiency	80%
Boiler TDS Level	2000 ppm
Condensate Return	50%
Condensate Temperature	80 °C
Make-Up Water Temperature	10 °C
Make-Up TDS Level	300 ppm
Feed Tank Pressure	0 barg
Dosing TDS Increase	69 ppm
Operation	6000 h/y
Fuel Cost	9.47 $/MWh

Potential Improvement Projects

Condensate Return	80%	☑
Allowable TDS	3500 ppm	☑
Blowdown Flash	0 barg	☑
Blowdown HX	10 °C approach	☑
Boiler Efficiency	85%	☑

Potential projects ticked

The value of the model here is demonstrated by the fact that it is assessing the interactions between the projects to arrive at the true saving. If the project savings were calculated individually for each project, the sum of the savings would appear to be greater than $116,100 per year because some of these projects are competing for the same energy saving. The model therefore allows us to calculate the true, cumulative savings and, importantly, to draw up a plan of staged investment so that the projects can be ranked in order of attractiveness and form the basis of a coherent investment plan.

The above use of a steam model is typical of the off-line, planning application. It essentially tells us how the system will react to certain future operational scenarios whether they are future projects, new process demands or new energy prices. The model is essentially operating as a simulator to reflect the behavior of the system as it is presently configured.

If there are a number of degrees of freedom available to the utility system operator (steam turbine or electric motor drive, variable load turbo-generators, or even intentional steam venting), then a model can be constructed that doesn't simply predict the behavior of the existing system in a particular configuration but actually tells us which is the optimum system configuration we should be employing. This is referred to in this paper as the optimizer model.

Figure 4 illustrates a simple system with some basic degrees of operational freedom.

It shows a utility system that contains a process drive (500kW) that can be either an electric motor or condensing turbine, a variable extraction/condensing turbo-generator and the ability to vent low-pressure steam. The base case operation shown here is for a power-to-heat ratio of 4:1. In other words, a megawatt of purchased electrical power costs four times as much as a megawatt of fuel. Under these conditions, the optimum process drive is the electric motor and condensing in the main turbo-generator should be zero. In reality, it may not be possible to reduce the condensing flow to zero for mechanical reasons—this is simply an illustration. Hourly cost of operation is calculated to be 54.2 cost units per hour.

Now consider the possibility of the power:heat cost ratio increasing to a value of 6:1, perhaps because of high electricity costs at particular times of day (time-of-day tariff). Under these conditions, we can input the figure of 6:1 and press the optimizer button in the model. Figure 5 illustrates the input/output screen of the model.

This immediately flags up operator instructions to switch on the condensing section of the turbo-generator and to switch to the steam turbine process drive. We are presented with the flow diagram in Figure 6 which indicates an hourly cost

Figure 4: Base Case Operation

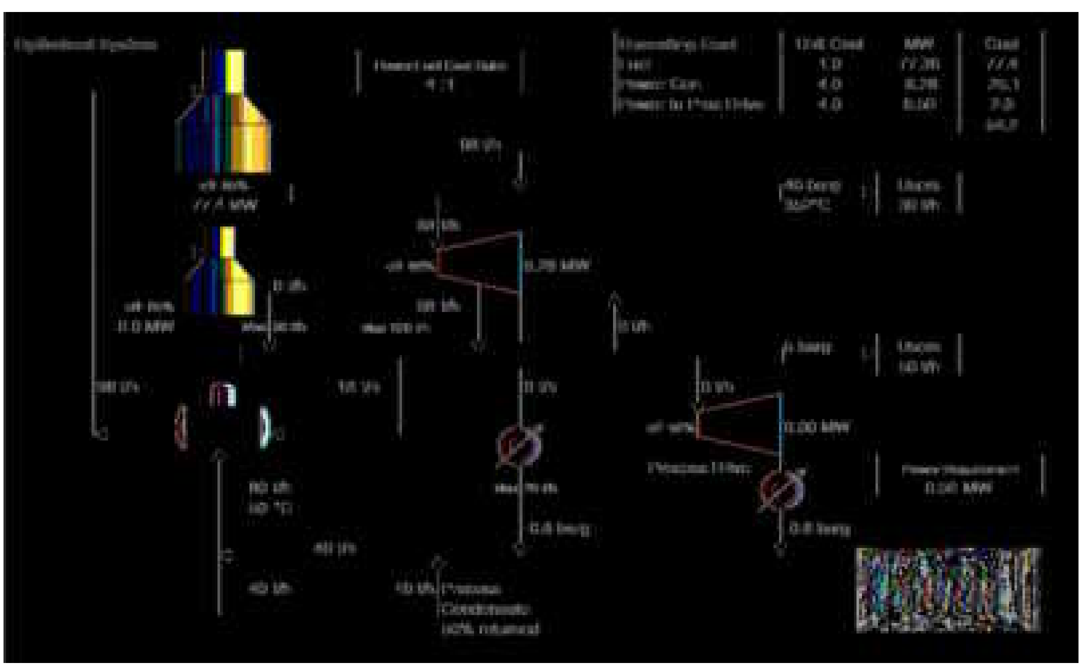
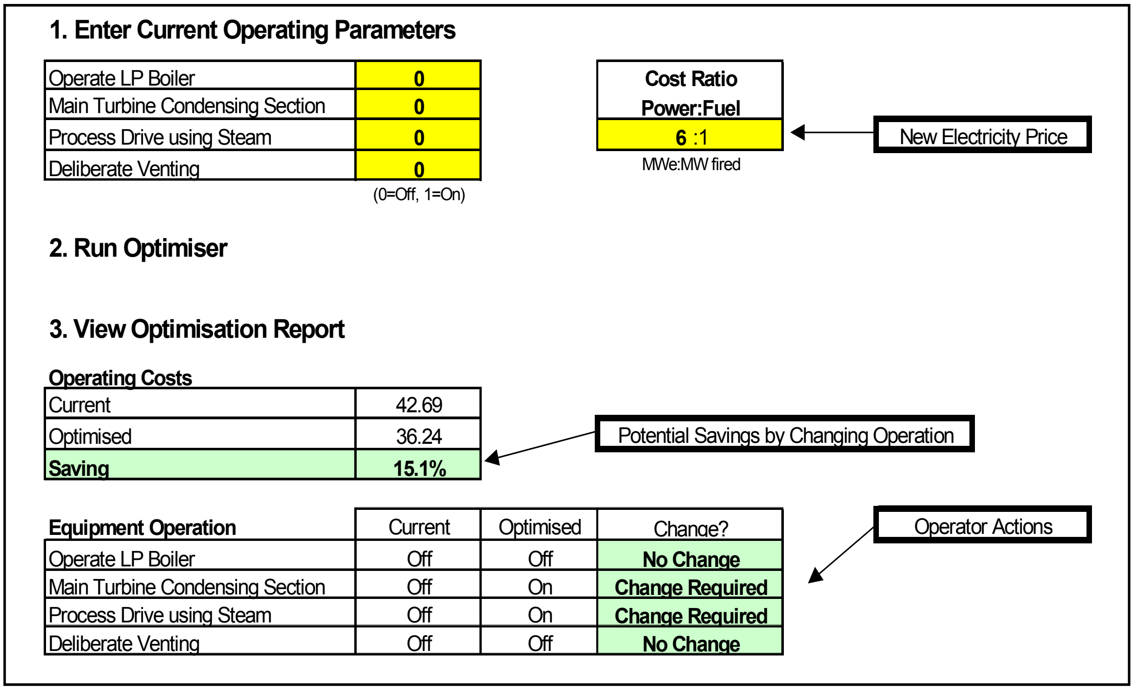


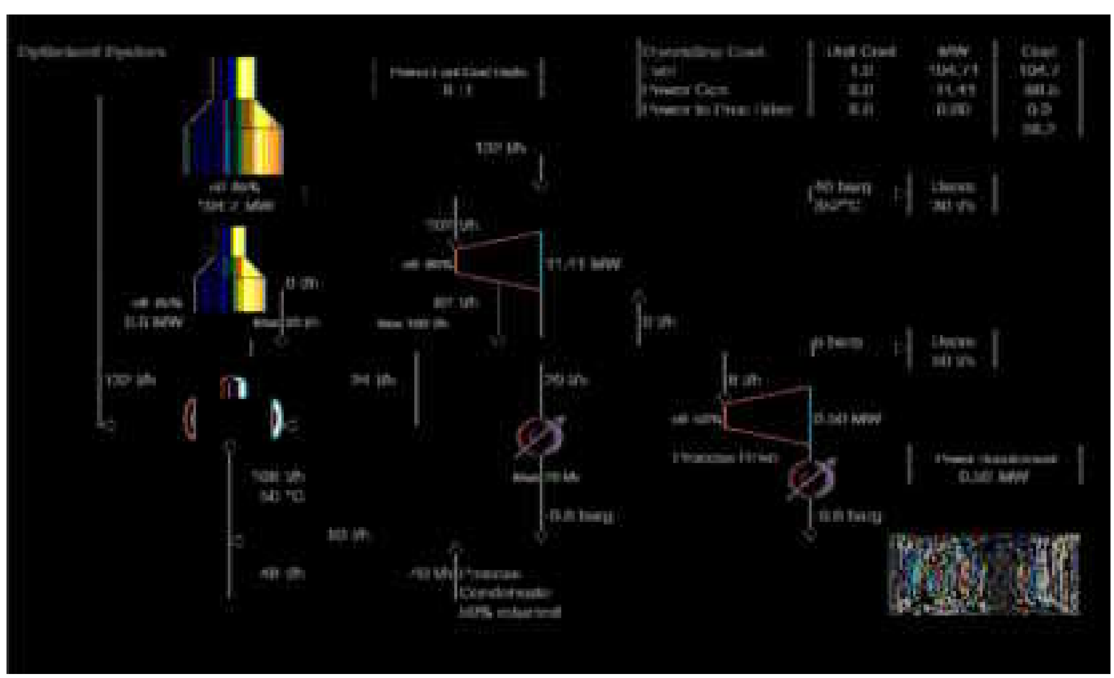
Figure 5: Operator's Screen



of 36.2 cost units which compares favorably with the value of 42.7 which would be the case if the operator action were not taken, a saving of 15%. This simple example illustrates the additional functionality of the optimizer model over the planning model. Whereas the planning model allows us to assess the effect of project and process changes on the existing configuration of the steam system, the optimizer model allows us to be proactive in determining the best configuration of the steam system under present or future operating scenarios.

A planning model in the above example would have evaluated the savings we could obtain under the base case configuration and this would be the

Figure 6: Optimum Operations at an Increased Power Cost



value shown in Figure 5 as "current operating costs" (42.7 cost units compared to the base case cost of 54.2 in Figure 4). The optimizer has taken this a step further and identified even lower operating costs (36.2 cost units) by suggesting changes to the configuration of the steam system as indicated.

Industrial Case Study

Linnhoff March has built more than 100 steam system models in recent years and all of them have identified ways in which a system can be improved, either operationally or through capital projects. Many of these models have been created for large oil refineries of which the following is a typical example.

Figure 7 shows a simplified drawing of a UK oil refinery steam system.

The refinery low-pressure steam system contains two separate sections. Due to site expansions, one element of the low-pressure system was in deficit and pulling large amounts of steam down from a much higher pressure. The other element of the low-pressure system was in surplus with regular venting of excess steam to atmosphere.

The almost trivial (in retrospect) solution of connecting the two elements of the low-pressure system considerably improved the overall steam balance (Figure 8). The relatively short crossover connection paid back within a matter of weeks.

Because of the complexity of operations on the site, plant personnel had not previously spotted this opportunity and it probably is not an isolated example. Building a model of the overall steam system for the first time allowed a consistent analysis to be carried out of the whole system rather than simply rely on local, ad-hoc improvements.

This type of modeling has been applied by Linnhoff March in over 100 site applications and operational savings of between 1-5 percent have been achieved. When added to the benefits of capital project savings identified by the planning model, total energy savings regularly amount to 15 percent.

Benefits

Many of the benefits of an accurate site steam model have already been described in this paper.

To summarize, off-line planning models provide the following benefits:

- Improved utility cost accounting
- More reliable project screening
- Enhanced understanding of the steam system through the identification of key controllable parameters
- Better contract management of purchased utilities (fuels, electricity)
- Identification of no-cost operational improvements
- Reliable reporting of emissions
- Utilities configuration planning (daily, weekly, monthly)

Figure 7: Existing Refinery Steam Balance

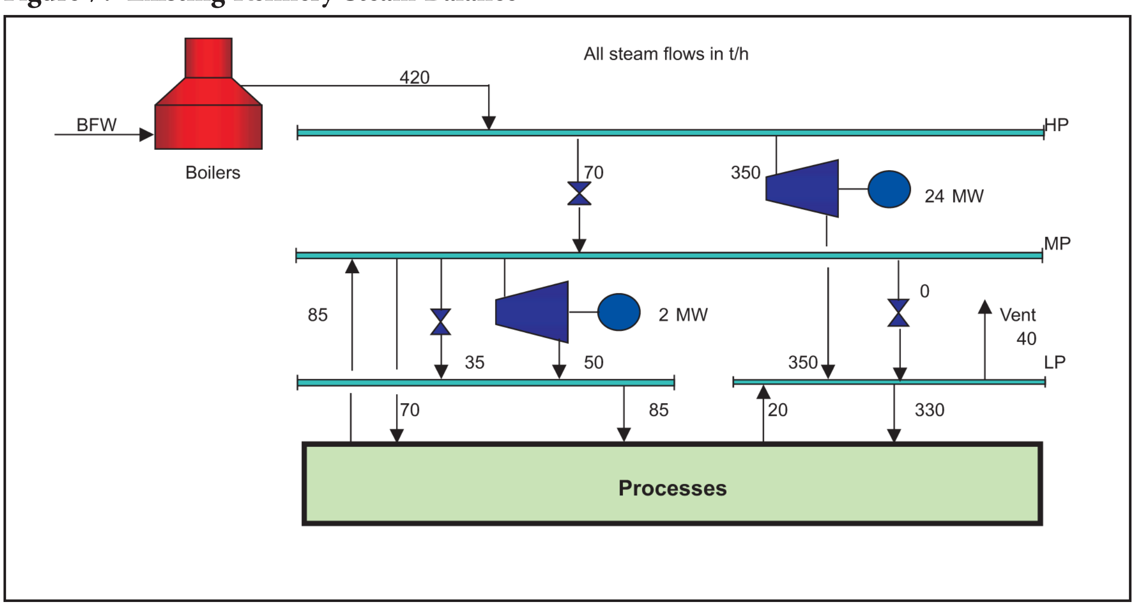
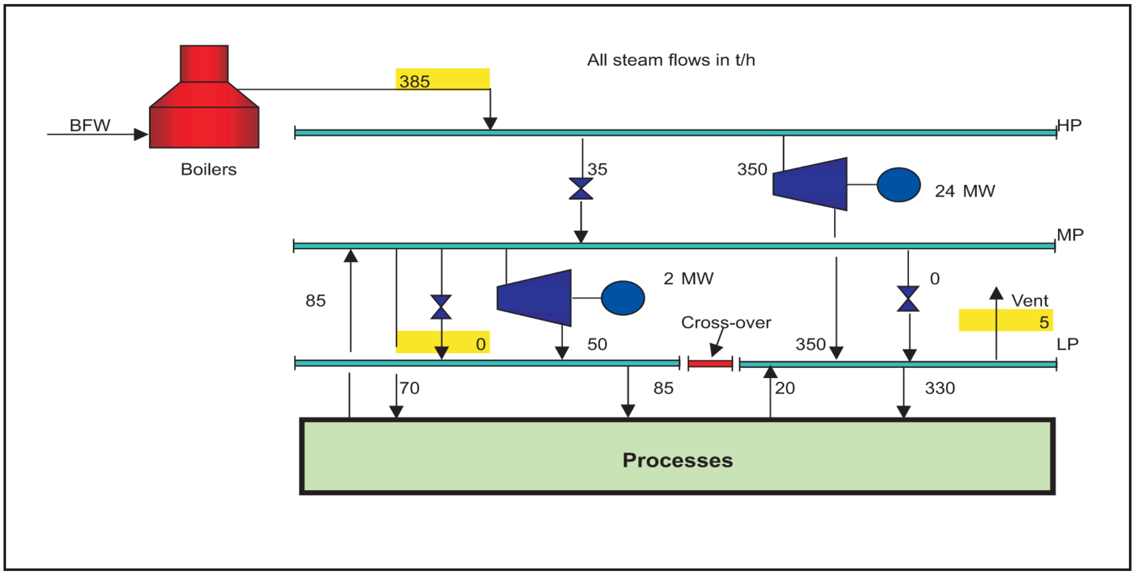


Figure 8: Improved Refinery Steam Balance



- Basis for strategic investment "RoadMaps"

On-line (open loop) systems can offer further benefits:

- Data validation and reconciliation
- Optimized utility system operation (hourly or daily basis)
- Plant performance monitoring

Cumulatively, these benefits can save 15 percent of current utility costs. This figure, of course, is somewhat dependent on the starting point for improvement, i.e., the current state of understanding of the system. Even from a relatively sophisticated starting point, we have seen no-cost savings of five percent in systems with six or more degrees of operational freedom.

Conclusions

Spreadsheet-based steam system models with a built-in physical properties database are a very cost-effective way of reducing the operating cost of steam generation and distribution and forming a consistent basis for future investment strategies.

The cost of building an off-line planning model will range from less than $10,000 for a simple, single steam level system up to $25,000 or more for a typical oil refinery or petrochemical complex. Converting such a base model to an on-line optimizer will roughly double the cost of the model. The cost of the actual software package on which the model is based is only a tiny fraction of the above costs.

Since potential benefits can be several million dollars per year on a large, complex site these models will pay back in a matter of weeks, if not days.

Such tools should be more widely adopted by industry for improved energy cost accounting and reduced operating costs with attendant reduction in the emission of greenhouse gases to the environment.

References

1. JD Kumana, "Use Spreadsheet-Based CHP Models to Identify and Evaluate Energy Cost Reduction Opportunities in Industrial Plants", 23rd IETC, Houston, May 2001.

Appendix

ProSteam™ by Linnhoff March provides a number of pre-formatted plant equipment models for setting up site utility simulations. The model functions currently available are:

Steam Turbines

Trbn_A	Single-Stage Steam Turbine model (Mass flowrate specified).
Trbn_B	Single-stage Steam Turbine model (Power generation specified).
Trbn_A2	Two-Stage Steam Turbine model (Mass flowrate specified).
Trbn_B2	Two-Stage Steam Turbine model (Power generation specified)

Trbn_A3	Three-Stage Steam Turbine model (Mass flowrate specified)
Trbn_B3	Three-Stage Steam Turbine model (Power generation specified)

Heat Exchangers

HtExchngr_A	Water/Steam heat exchanger based on fluid conditions
HtExchngr_B	Water/Steam heat exchanger based on duty
HX_Process To Process	Process/Process heat exchanger U, A, Nshells & Cp specified
HX_UA_ Exchanger	UA based heat exchanger - U,A, LMTD & Ft specified
HX_BFW Heater	UA Boiler feed water heater (Process/Water exchanger)
HX_Steam Generator	Steam Generator (process/water-steam heat exchanger)
HX_Ft	Exchanger Ft factor
HX_LMTD	Exchanger LMDT
HX_NoShells	Exchanger - Number of Shells
HX_UA	Exchanger UA (also Ft and LMTD)
HX_FlowFactor	Flow Adjustment Factor - for heat transfer coefficient
Calc_Cp	Specific Heat Capacity calculation
Calc_CpMean	Specific Heat Capacity (Mean) calculation

Gas Turbines

GTurb_A	Gas turbine model
GTurb_B	Gas Turbine with varying air temperature or injection steam conditions

Fuels

Fuel LHV	Fuel Lower Heating Value
Fuel Name	Fuel Name
Fuel Descr	Fuel Description

Boilers

Blr_A	Simple Boiler model. (A)
Blr_B	Simple Boiler model. (B) with firing efficiency.
Blr_C	Advanced Boiler model with emissions calculations.

Compressors

ThermoComp_A	Thermocompressor – Rating model.
ThermoComp_B	Thermocompressor – Design model.
Cmprssr_A	Single-Stage Compressor model (Mass flowrate specified).
Cmprssr_B	Single -Stage Compressor model (Power specified).
Cmprssr_A2	Two-Stage Compressor model (Mass flowrate specified).
Cmprssr_B2	Two-Stage Compressor model (Power specified).

Miscellaneous

Drtr_A	Deaerator model.
DSprHtr_A	De-superheater model (Inlet Steam Flowrate Specified).
DSprHtr_B	De-superheater model (Outlet Steam Flowrate Specified).
FlshVssl_A	Flash Vessel model.
WaterPump_A	Water Pump Model
LtDwnVlv_A	Let-down Valve model.

Steam System Improvements at Dupont Automotive Marshall Laboratory

Andrew Larkin, P.E., C.E.M., Trigen-Philadelphia Energy Corporation

Abstract

Dupont's Marshall Laboratory is an automotive paint research and development facility in Philadelphia, Pennsylvania. The campus is comprised of several buildings that are served by Trigen-Philadelphia Energy Corporation's district steam loop. In 1996 Dupont management announced that it was considering moving the facility out of Philadelphia primarily due to the high operating cost compared to where they were considering relocating. The city officials responded by bringing the local electric and gas utilities to the table to negotiate better rates for Dupont. Trigen also requested the opportunity to propose energy savings opportunities, and dedicated a team of engineers to review Dupont's steam system to determine if energy savings could be realized within the steam system infrastructure.

As part of a proposal to help Dupont reduce energy costs while continuing to use Trigen's steam, Trigen recommended modifications to increase energy efficiency, reduce steam system maintenance costs and implement small scale cogeneration. These recommendations included reducing the medium pressure steam distribution to low pressure, eliminating the medium pressure to low pressure reducing stations, installing a back pressure steam turbine generator, and preheating the domestic hot water with the condensate. Dupont engineers evaluated these recommended modifications and chose to implement most of them.

An analysis of Dupont's past steam consumption revealed that the steam distribution system sizing was acceptable if the steam pressure was reduced from medium to low. After a test of the system and a few modifications, Dupont reduced the steam distribution system to low pressure. Energy efficiency is improved since the heat transfer losses at the low pressure are less than at the medium pressure distribution. Additionally, steam system maintenance will be significantly reduced since 12 pressure reducing stations are eliminated. With the steam pressure reduction now occurring at one location, the opportunity existed to install a backpressure turbine generator adjacent to the primary pressure reducing station. The analysis of Dupont's steam and electric load profiles demonstrated that cost savings could be realized with the installation of 150 kW of self-generation. There were a few obstacles, including meeting the utility's parallel operation requirements, that made this installation challenging.

Over two years have passed since the modifications were implemented, and although cost savings are difficult to quantify since process steam use has increased, the comparison of steam consumption to heating degree days shows a reducing trend. Dupont's willingness to tackle energy conservation projects without adversely affecting their process conditions can be an example to other industrial steam users.

Introduction

Dupont's Marshall Laboratory has been an automotive paint research and development facility in Philadelphia, Pennsylvania since the early 1900s. The first building was built in 1901, before it was a Dupont site. Dupont has developed several automotive paint innovations at this Philadelphia site. While their primary R&D focus is the development of better automotive paints, Dupont Marshall Lab scientists and engineers also work on other projects such as developing improved computer printer inks.

Several buildings receive steam from Dupont's aboveground and buried steam distribution piping. The Trigen steam loop supplies steam under the streets of Philadelphia to Dupont Marshal Lab and over 300 other customers, including the University of Pennsylvania, the U.S. Mint, the Philadelphia Art Museum, and most of the center city hospitals. The majority of the steam is generated from the Grays Ferry Cogeneration Plant, which is a combined cycle (brayton cycle and rankine cycle) cogeneration plant that includes a dual fuel (gas and oil) combustion turbine generator and a steam turbine generator. This plant provides 150 MW to the local electric grid operated by PJM Interconnection LLC, and can produce up to 1.4 million pounds of steam/hour.

When Dupont notified city officials in 1996 that it was considering moving their research and development facility to the south due to the high cost of operating in Philadelphia, and energy costs were a significant component of their operating costs. The city responded by bringing the local electric and gas utilities to the table to negotiate better rates for Dupont. Since Dupont was one of Trigen's largest and most valued steam customers, Trigen dedicated a team of engineers to review Dupont's steam system to determine if energy savings could be realized within the steam system infrastructure.

Steam System Recommendations

After walking down the Dupont steam system and listening to Dupont engineers describe how the steam is used in different areas, Trigen recommended modifications to reduce heat transfer energy losses, reduce steam system maintenance costs and implement small-scale cogeneration. Specific recommendations included reducing the medium pressure steam distribution to low pressure, eliminating the medium pressure to low pressure reducing stations, installing a backpressure steam turbine generator, and recovering the heat from the condensate. Dupont engineers and an independent energy consultant evaluated the recommended steam system modifications and decided to go forward with them, except for the recommendation to preheat the domestic hot water.

Steam Distribution Efficiency Gain

Dupont received steam from Trigen at 210 psig, and reduced it all to 150 psig in a pressure reducing station. Some of this steam was used at 150 psig for process use, and the rest was reduced to 120 psig in another pressure reducing station to be distributed to several buildings. The steam pressure was further reduced to 15 psig at 12 separate pressure reducing stations where the steam was used for heating, humidification and domestic hot water.

Since Dupont had received steam from the steam loop for several years, historical hourly steam consumption was readily available. Trigen metered the steam with a vortex meter and an automatic data acquisition system that downloading the data to Trigen via modem. An analysis of Dupont's past steam consumption showed that the steam distribution piping system sizing was acceptable if the steam pressure was reduced from 120 psig to 15 psig. The basis for this determination was to keep the steam velocity below 6000 feet per minute (fpm) to avoid excessive noise, premature wear, and significant pressure drop. In a process steam environment, a steam velocity as high as 12,000 fpm would be acceptable if noise is not a factor, but a significant portion of this Marshall Lab facility is office or research areas where noise would be a distraction. The steam velocity can be calculated simply by using the following equation:

$V = 2.4QVs/A$ Equation (1)

Where:
V = Velocity in feet per minute
Q = Flow in lbs/hr steam
Vs = Sp. Vol. In cu. Ft/lb at the flowing pressure
A = Internal area of the pipe in sq. in. [1]

Given a maximum velocity of 6,000 fpm, the maximum steam flow throughout each section could then be calculated. Dupont provided piping drawings showing the diameter of each pipe section. Unfortunately the exact steam flow to each building was not known since there were no submeters. However, in all cases, the calculation of the maximum allowable steam flow in each section was greater than the rule of thumb amount of steam/sq.ft. heating area needed for each building. In order to ensure a successful transition to low pressure distribution, a test of the system was conducted using the manual bypasses around each of the low-pressure pressure reducing valves (PRV) and adjusting the pilot at the main pressure reducing valve to slowly reduce pressure from 150 psig to 15 psig. Fortunately, with only one exception, the bypasses around the PRV stations were also properly sized for low-pressure steam. After a successful test of the system and a few minor modifications, Dupont reduced the steam distribution system to low pressure.

This modification improved energy efficiency since the heat transfer losses through the pipe and insulation at a lower temperature are less than the heat transfer losses at a higher temperature. An estimate of reduced condensate losses was estimated using the following equation at 125 psig and at 15 psig:

$C = (A * U * (t_1 – t_2) * E)/H$ Equation (2)

Where:
C = Condensate in lbs/hr-foot
A = External area of pipe in square feet
U = Btu/sq ft/degree temperature difference/hr
T_1 = Steam temperature in °F
T_2 = Air temperature in °F
E = 1 minus efficiency of insulation
H = Latent heat of steam [2]

Since all of this condensate is disposed of rather than sent to a condensate return system, minimizing condensate losses directly minimizes steam consumption.

Steam System Maintenance Savings

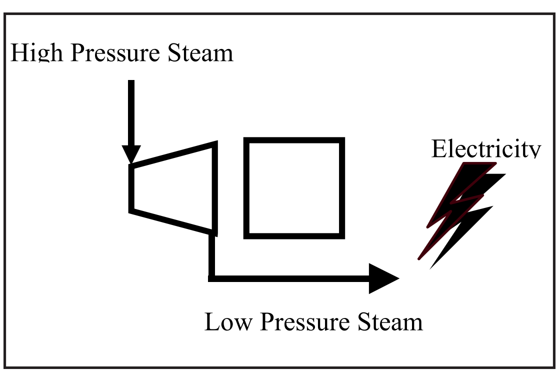
Additional cost savings are realized by the significantly reduced maintenance required since 12 pressure reducing stations are eliminated. Each pressure reducing station typically includes isolation gate valves, a bypass globe valve to enable manual throttling of the steam, a strainer, a steam trap and a pressure relief safety valve, in addition to the PRV. Properly selected PRVs need to have seats replaced about every five years, while incorrectly sized PRVs may need new seats as frequently as each year. Additionally, steam losses due to weeping safety valves and leaking flanged or screwed connections could be reduced. Although it is difficult to exactly quantify these costs, a savings of $25,000/year due to eliminating these pressure reducing stations is realistic.

Backpressure Turbine Generator Installation

Since Trigen's steam pressure supplied to Dupont is nominally 210 psig, and all of the pressure reduction could now take place at one location, the opportunity existed to consider the installation of a backpressure turbine generator. As illustrated in Figure 1, a backpressure turbine generator takes the place of a PRV by reducing the pressure from high pressure to low pressure.

While the steam is losing pressure, it is rotating a turbine that rotates a generator and generates electricity. The PRV parallel to the turbine is set about 2 psig below the turbine output to enable the PRV to automatically pick up the steam flow if the turbine trips for any reason.

In addition to needing an acceptable pressure reduction, an analysis of the electric usage is necessary to determine if installing a backpressure



turbine generator is viable. Dupont was on a high-tension service electric tariff that included an electric demand ratchet payment. Basically, the billed monthly demand is the greater of the maximum registered demand during the month, or 80 percent of the peak demand during the previous June through September months. Fortunately, Dupont's annual electric load profile was flat enough such that the actual demand during the winter months was more than 80 percent of the peak demand during the summer months. Accordingly, the billed demand each month was the actual billed demand set during that month.

An analysis of Dupont's annual steam and electric loads was done to determine the optimum size for the backpressure turbine generator. Since there were no steam submeters after the main meter, the amount of steam used at low pressure was not exactly known. However, since the summer steam load was nearly all process load used at high pressure, it was safe to assume that this process load was fairly constant throughout the year. Based on the remaining load after the estimated high-pressure process load was removed, a 150 kW backpressure turbine generator was selected. Since the 150 kW output of this generator is far less than the electric capacity Dupont needed, this unit would be operating parallel to the electric service supplied by the local electric utility. The local utility required the review and approval of an application for parallel operation before the turbine generator could be installed. This is necessary to verify that the installation will operate safely in parallel to the grid, and to verify that the power quality of the grid is not reduced such that it would affect other utility customers in the vicinity. Since this generator is an induction generator, the unit is automatically synchronized by the utility electric service, and would instantly shut down if the utility service is interrupted. Ultimately, the electric utility approved the installation after a satisfactory test of the relay protection system.

The turbine generator was installed adjacent to the primary pressure reducing station. Since this pressure reducing station was located in a separate steam metering building, the electric from the turbine generator was tied into a motor control center in the adjacent building.

Preheating Domestic Hot Water

In addition to the energy conservation recommendations that Dupont implemented, preheating the domestic hot water with condensate was also recommended. Since the district steam loop in

Philadelphia was installed during a time when water and energy were relatively inexpensive, the steam loop was not installed with condensate return piping. Accordingly, after the energy is removed from the steam, the remaining condensate is sent to the sewer. However, this condensate often has useful energy remaining. Also, since the local code requires the water to be 140°F before it goes to the sewer, often water must be added to it to quench the condensate as needed. Therefore, instead of wasting useful energy and potentially useful water, Trigen recommended adding a heat exchanger to transfer the useful heat from the condensate to water used for domestic hot water heating.

The amount of energy available from the condensate can easily be determined. Assuming that the condensate is saturated at 200°F, the enthalpy would be 168 Btu/lb. If the heat exchanger is designed to reduce the condensate to 100°F (based on an adequate cold water flow), the leaving enthalpy would be 68 Btu/lb. Therefore, 100 Btu/lb are available for preheating domestic hot water, which means that for every pound of steam that is used, 100 Btu can be used for preheating domestic hot water.

The amount of water used to quench the condensate to 140°F that can be avoided by preheating domestic hot water also can be easily estimated. Given the conservation of energy for a steady state energy balance, assuming the kinetic energy changes of the flow stream are negligible:

$$m_1h_1 + m_2h_2 = m_3h_3 \qquad \text{Equation (3)}$$

Where:
m_1 = mass of condensate, lbs.
h_1 = enthalpy of condensate, Btu/lb.
m_2 = mass of cooling water, lbs.
h_2 = enthalpy of cooling water, Btu/lb.
m_3 = mass of mixture, lbs.
h_3 = enthalpy of mixture, Btu/lb. [3]

Since $m_1 + m_2 = m_3$ (conservation of mass), and all of the enthalpies are known assuming saturated condensate at 200°F, saturated cooling water at 60°F, and a saturated mixture at 100°F, the mass of the cooling water needed can be found for a given amount of condensate. It is often surprising to go through this exercise and find out the actual cost of water needed for quenching. Note that since domestic hot water is typically an intermittent need, some water would still be needed to quench the condensate when preheating is not possible.

At Dupont's Marshall Laboratory, the amount of condensate available near the domestic hot water heating is not centralized, making it difficult to assess the amount of condensate available near the domestic hot water heaters. Accordingly, we could not assess the payback on the cost of installing heat exchangers and associated piping condensate pumps and valves as needed. Therefore, domestic hot water preheating was not done to date.

Measured Savings

Over two years have passed since the modifications were implemented, and although cost savings are difficult to quantify, the comparison of steam consumption to heating degree days shows a reducing trend. Heating degree days (HDD) is basically a measure of the amount of days that heating is needed, and is calculated by subtracting the average ambient temperature from 65. Historical steam usage has shown that steam consumption is closely correlated to heating degree days. In order to accurately determine if the steam system modifications have resulted in more efficient steam use, the annual comparisons need to be relative to heating degree days. The graph shown in Figure 2 below of annual steam consumption in Mlbs (one thousand pounds) vs HDD clearly shows a trend of reduced steam consumption from the start of the modifications in 1998 through 2000.

The increase in the Mlb/HDD ratio in 2001 likely occurred due to the combination of two factors: the process steam consumption has increased, and the 2001 heating degree days were considerably lower than average, making the process load a larger percentage of the total consumption. In 2001, Dupont modified some process reactors to use high-pressure steam as the heating source. This process change added steam load at high pressure, bypassing the backpressure turbine generator and the low-pressure distribution. The heating degree days in 2001 were 3,984 compared to an average of 4,355 over the six years shown in the Figure 2 graph.

Lessons Learned

The following lessons from this case study can be applied to other industrial steam systems:

1. Ensure steam distribution pressure is as low as possible.

   Since lower pressure steam correlates to lower temperatures (assuming saturated steam), reducing the pressure as much as possible results in a lower delta T between the steam temperature and the ambient temperature, which results in less heat transfer losses. Note that this case study is based on reducing the steam pressure in a distribution system when the steam pressure at the generating source cannot be reduced. If it is possible to reduce the steam generation pressure, the efficiency gains by distributing at a lower pressure must be weighed against the reduced efficiency resulting from a steam generator operating at less than design pressure.

2. Consider backpressure steam turbine generator if steam generation pressure is greater than pressure needed at the point of use.

   Packaged backpressure turbine generators are available as small as 50 kW. If at least 3,000 lb/hr must be reduced from high pressure to low pressure, and higher cost electricity can be displaced, the opportunity exists to install a backpressure turbine generator.

3. Transparent improvements in steam systems can make a significant impact on the bottom line.

   By evaluating exactly what steam conditions are needed at the point of use, the upstream steam system design should be made as efficient as possible. If steam usage has changed since the steam system was started, there may be an opportunity to improve the efficiency.

Conclusion

The steam system improvements made at Dupont's Marshall Laboratory all involved basic concepts that were easily implemented without negatively impacting processes or building comfort. The key to this case study is Dupont's willingness to identify all energy conservation possibilities and go forward with those that provide an acceptable payback. All too often, the utility systems in industrial facilities are seen as a necessary evil, and energy savings projects are ignored since the capital that is saved is small compared to the overall costs at industrial facilities. However, as long as the energy savings project provides an acceptable pay back on its own merits, it should be implemented.

If all industrial steam users evaluated their steam systems and completed all modifications that provided an acceptable payback, our country would be taking a significant step toward reduced reliance on fossil fuel from other countries. Additionally, by generating a portion of the electricity without any emissions whenever the opportunity exists, we are also taking a step toward cleaner air.

References

1. Spirax Sarco, Design of Fluid Systems, 1997, p. 3
2. Armstrong International Inc., Steam Conservation Guidelines for Condensate Drainage, 1993, p. 17.
3. Wark, Kenneth Jr., Thermodynamics. 5th ed. NewYork: McGraw-Hill, 1988.

Closed-Loop Energy Management Control of Large Industrial Facilities

Ronald L. Childress, Jr., Automation Applications, Inc.

Abstract

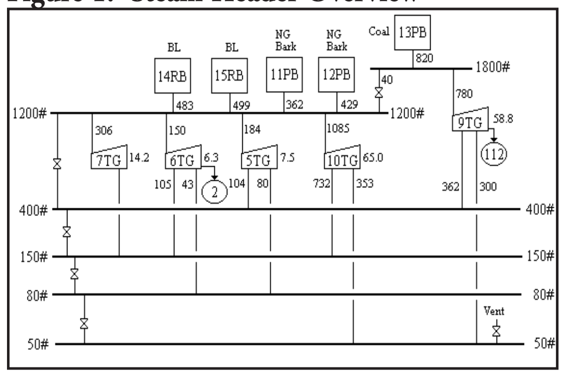
A case study is presented of a closed-loop control system installed and running at a pulp and paper facility in the southeast. A fuzzy logic, ruled-based control system optimally loads multiple steam turbines for maximum electrical generation, while providing steam to the process. A Sell Advisor calculates make–buy decisions based on real-time electrical prices, fuel prices and boiler loads. Condensing turbines are coordinated with closed-loop control to provide the lowest energy cost to the plant. When economical, additional electrical generation is achieved by venting low-pressure steam. By manipulating turbine loads, boilers are pushed to optimal loading through process coupling. Multi-variable control strategies push process envelopes to constraints.

Background

Deregulation of electricity and rising fuel costs are causing renewed interest in energy management systems (EMS). This paper details the results of integrating a rule-based EMS controller at a pulp and paper mill and additional findings from several other large industrial power complexes. It is a computer-based supervisory system that is interfaced to a distributed control system (DCS). The EMS has been applied on powerhouse complexes as large as 433 MW of electricity and 7,500 KPPH of steam. The EMS may, as required, include boiler load allocation, steam turbine load allocation, combustion turbine and heat recovery steam generator load allocation, real-time pricing (RTP) tie-line control, coordinated header pressure control, bus voltage and plant power factor control and electric and steam economic load shed systems. It optimizes the powerhouse operations to meet rapidly changing steam and electrical requirements of the plant at minimum cost subject to all of the operating constraints imposed on the generation equipment.

It is critical to control the trajectory of the power generation for optimal steam and electric moves while satisfying multiple constraints. The optimization strategy applied here is reduced to a fairly small number of prioritized rules. It has proven itself capable of optimizing large powerhouse complexes while keeping the powerhouse and process units within a safe operating envelope.

Figure 1: Steam Header Overview



The purchased energy (fossil fuel and electricity) cost component for producing a product can be significant, and small incremental changes can make a big impact on the profitability of a plant. The plant studied here is minimizing purchased fuel and maximizing waste fuel usage to reduce energy cost and emissions.

The powerhouse has a number of environmental, equipment and process constraints that must be adhered to as the powerhouse equipment is maneuvered to meet the mill's energy demand at the lowest possible cost. Balancing the optimization functions with all of those constraints is a difficult task requiring a significant amount of operator intervention. A closed-loop, multi-variable, EMS is used to control multiple operating objectives.

Control Objectives

Several objectives were identified and prioritized as follows:

1. Maximize steam supplied by self-generated waste fuel sources such as hog and black liquor.
2. Optimize power boiler loading to produce the mill's steam requirement at the lowest cost.
3. Balance turbine loads to produce maximum electrical generation while supplying process steam.
4. Manage turbine condensing to buy, make or sell power based on electrical schedules and real-time electrical prices, fuel costs and boiler efficiencies.
5. Vent 50-psig steam to generate additional electricity when economical based on real time prices, fuel costs and boiler efficiencies.

Buy/Sell Advisor

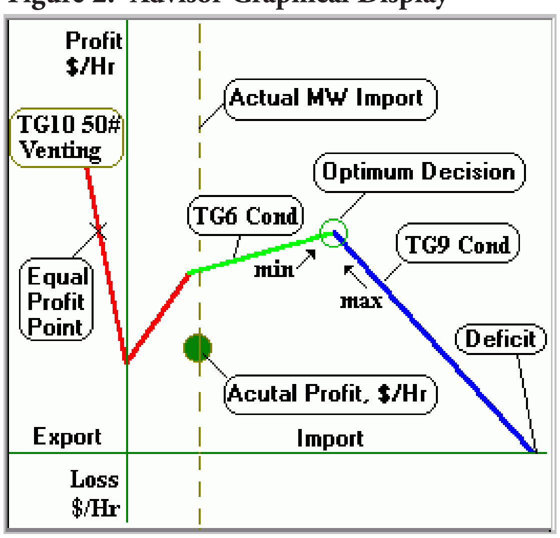
An operator sell advisor was developed for the following reasons:

1. Show operators how to optimally load turbines.
2. Calculate global buy/make/sell purchase decisions based on incremental cost calculations and risk assessment.
3. Provide performance indicators to track EMS performance.

Optimal turbine loading is displayed to the operators both graphically and numerically. Each line is color coded to represent a specific turbine extraction, exhaust or condensing flow. Incremental fuel costs, boiler efficiencies and turbine stage efficiencies contribute to changes in the overall cost of energy.

Shown in Figure 2, the vertical axis represents potential $/hr. profit or loss. The horizontal axis represents electrical power export or import in Megawatts. Shown at the far right is the electrical deficit. Electrical deficit is defined as the difference between total plant electrical load minus megawatts produced internally with minimum turbine condensing and no venting to the atmosphere. Profit or loss is compared against buying all of the electrical deficit. Every 15 minutes, real-time electrical prices are downloaded automatically by EMS. Based on incremental cost calculations, EMS continuously decides to make or buy the electrical deficit while observing multiple constraints.

Figure 2: Advisor Graphical Display



The graph in Figure 2 indicates the optimum decision is to maximize TG9 condensing load and minimize TG6 condensing load. Increasing TG6 condensing load reduces $/hr. profit. The dashed, vertical line shows current tie-line power import. In this case, TG9 condensing should be maximized and TG6 condensing should be minimized to maximize overall profit. On EMS control, TG9 and TG6 condensing loads are maneuvered automatically to maximize profit.

Sometimes, selling power to the grid may be profitable based on current electrical prices. As shown in Figure 2, a conflicting decision is often seen where it is better to buy the electrical deficit than to make it, but possible to sell power at a profit.

In Figure 2, an equal profit point represents the minimum amount of power that must be sold to match profits obtained by optimally purchasing power. Under these conditions, EMS decides to buy or sell based on risk assessment calculations. Risk calculations are based on potential return on investment versus the potential loss trying to obtain the return. Risk factors include current equipment loading, process stability and real-time electrical prices. Risk factors are adjustable to match Operations' comfort level. Advice is summarized, as shown Figure 3.

Performance Indicators

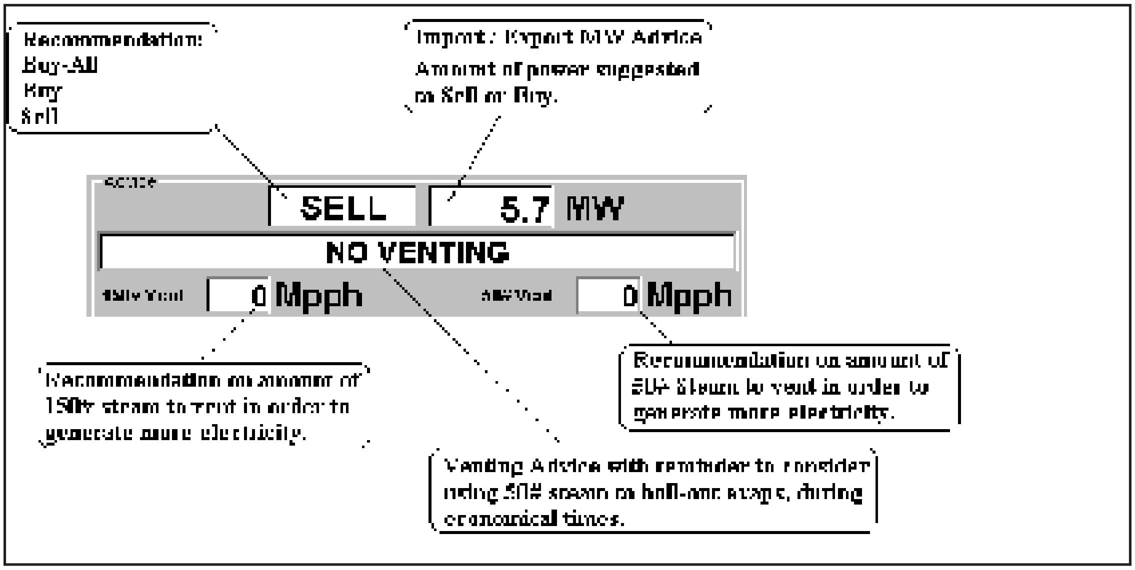
In Figure 4, a performance display is provided to show either Operator or EMS performance based on current operating conditions and incremental profit calculations. The display indicates maximum and actual $/hr. profit values and shows potential savings possible. A performance bar shows overall economic header balance in degrees of good or bad.

EMS Benefits

EMS has been in continuous automatic operation at this site since April 2001. Many significant benefits have been achieved:

1. Substantial reduction in overall cost of energy
   - Reduced natural gas usage
   - Reduced overall steam production
   - Reduced overall cost of electrical deficit
   - Reduced overall turbine condensing
   - Reduced selling of electrical power
   - Increased turbine power from process steam
   - Less venting during transient upsets

Figure 3: Advice



2. Greater power boiler operating stability
   - Reduced natural gas usage
   - Higher percentage of steam from hog fuel
   - Considerable cost savings
3. Reduced power boiler steam production
   - Reduced steam production overall
   - Considerable cost savings
   - Reduced stack emissions
4. Stable operation identified bottlenecks
   - Units run consistently on the edge of optimal performance
5. System indicators identify constraints
6. Steam users report more stable header pressures
7. Accelerated Return on Investment (ROI)
   - Original ROI estimate was one year
   - Actual ROI was less than six months
   - Contractual performance testing was waived to maintain increase in profits!

The advantage of a rule-based system is to take the best engineering and operational knowledge and insert it into the control system to be operational 24 hours a day, seven days a week. EMS performs optimization functions while adhering to all constraints. Like the operator, EMS sacrifices cost optimization whenever a constraint is reached. This results in robust process control. The control priorities are:

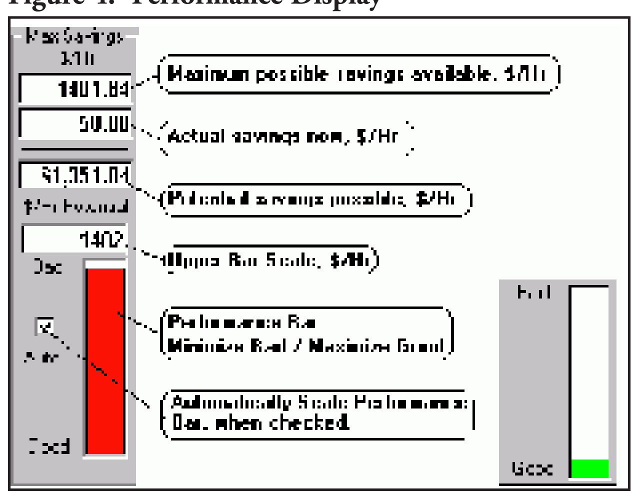
1. Meet all environmental constraints
2. Avoid equipment damage
3. Meet all process constraints
4. Assure utility delivery to process units
5. Meet energy requirements at minimum costs

Steam and Electrical Network

The powerhouse steam header overview is shown in Figure 1. More than half of the steam that is generated comes from burning process byproducts (black liquor and hog). Most of the process steam demand is for low-pressure steam. Steam is generated at higher pressures and throttled through the turbine-generators to lower pressure headers. A significant amount of electrical power, termed "extraction power" or "cogeneration", is generated as a result of this throttling action. PRVs offer an alternative way to throttle the steam to the lower pressure headers. However, since no power is generated, steam flows through PRVs should be minimized.

There is significant variability in the process steam and electrical power demand. Batch di-

Figure 4: Performance Display



gester operation, wood yard log chippers, soot blowers, paper machine disturbances and pulping process upsets all contribute to this variability. A "sheet break" on a large paper machine and subsequent threading of the sheet can result in large sudden steam demand swings in a period of less than a minute. Sometimes the power boilers must go from maximum load to minimum load and back again to maximum load within several minutes. Power boilers seldom operate at steady state conditions unless they are base loaded, i.e., the boiler master is placed in "manual". It is this variability that makes real-time optimization of the powerhouse operations so challenging. Steady state optimization methods simply do not provide the solution when the process is rarely at steady state.

Energy Management System

A new type of EMS has been developed and implemented to minimize the total cost of energy required by an industrial facility. It coordinates and optimizes the generation and distribution of steam as well as the generation and purchase of electricity. It also controls the main steam header pressure. The EMS is a supervisory control system that works in tandem with regulatory controls residing in the powerhouse DCS and PLCs.

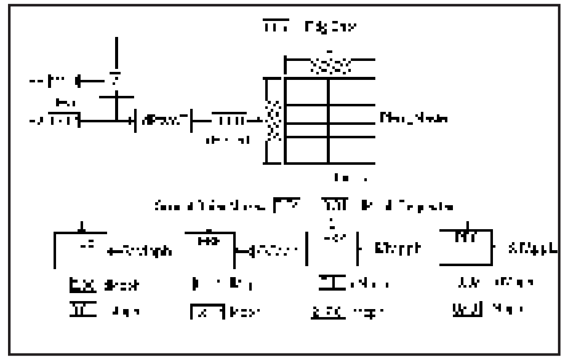
The EMS subsystems include boiler load allocation, turbine load allocation, hog optimization and demand or real-time pricing tie-line control. Each subsystem can be operated independently. The operator selects the subsystem and places it on EMS control. For boiler load allocation, the operator selects which boilers and fuels are to be used. The EMS control software resides in a Windows NT personal computer or can be installed directly in the DCS. It has been designed specifically for implementing fuzzy logic control. There are interfaces to the powerhouse DCS, turbine controllers and various PLCs.

Boiler Load Allocation

A schematic of a typical 1,200-psig header pressure control with an embedded boiler cost optimizer is shown in Figure 5.

The plant master is implemented with a fuzzy matrix controller that offers some significant advantages over a PID version. Fuzzy matrix controllers can exhibit superior control performance compared to a PID controller, especially for a nonlinear, complex process. The tuning of fuzzy controllers is a trial and error procedure that involves

Figure 5: Typical Boiler Cost Optimization

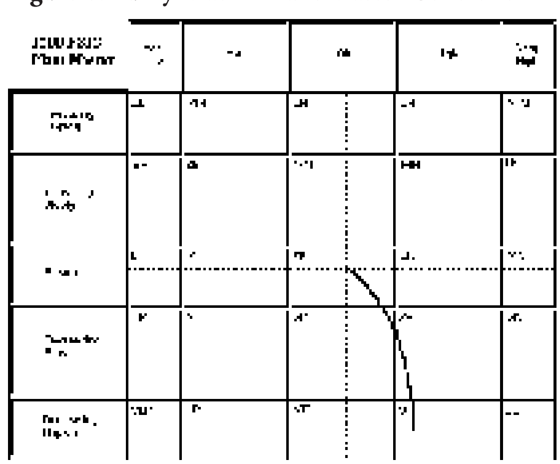


adjusting many parameters. A simple method to help with the tuning of fuzzy controllers has been developed. By overlaying a phase-plane plot on the rule matrix and analyzing the phase-plane trajectories, it becomes relatively easy to adjust membership functions and modify the rules to obtain the desired trajectories.

The fuzzy controller executes once per second and sends a request to the boiler cost optimizer for an incremental steam change. The boiler load optimizer design involves integration of three distinct functions. A safe operating envelope representing prioritized environmental, equipment and process constraints are defined which the allocator must respect. An optimization method is used which adjusts multiple boilers and fuels to obtain the most economical operating solution. The issue of header pressure control stability is addressed so power boilers with widely varying response capabilities can work in concert. Balancing these three functions is key to a successful design.

The boiler load allocator observes all predefined constraints before adjusting boiler fuel flows. These constraints create a safe operating envelope. Observing constraints prevents boiler damage and keeps the process out of undesirable operating re-

Figure 6: Fuzzy Matrix Plant Master Controller



gions. Constraints are prioritized in order of importance. Typical constraints for a boiler are (listed in order of priority):

1. Maintain opacity (6-minute average) below maximum.
2. Keep ID fan speed within control range.
3. Prevent furnace draft from going positive.
4. Maintain drum level in safe range.
5. Prevent excess oxygen from going too low.
6. Keep boiler steam generation within limits.

The boiler load allocation problem is analogous to the economic dispatching problem faced by an electric utility company whenever transmission losses can be ignored. For optimal allocation, the utilities must operate the units at equal incremental generating costs. Often the boiler load allocation problem has been posed as a static optimization problem. But in reality, the allocation function is embedded in the header pressure control loop that transforms it into a dynamic control problem. Since there are continuous disturbances to header pressure (caused by variations in steam demand), boiler load allocation also takes place on a continuous basis. Direct application of steady state optimization methods does not work for a process that is never at steady state. Instead, a dynamic boiler allocation method is used. In this solution, the optimization method has been converted to an optimization rule set that is integrated into the overall rule set.

An incremental steam generation cost (dollars per thousand pounds of steam) is continuously calculated for each boiler (fuel) based on the fuel cost (dollars per MMBtu), the selected swing fuel and incremental boiler efficiency for the selected fuel. This efficiency number is entered based on historical data or online calculations.

For incremental steam increase requests, boilers and fuels with lower incremental steam costs are favored more than boilers and fuels that have higher costs. All of the boilers move in concert to prevent one boiler from taking all of the load swings. For incremental steam decrease requests, boilers and fuels with higher incremental steam costs are favored. In the long run, the most economical boilers and fuels take most of the steam load. The more expensive steam producers are kept at a minimum value. In the short term, if more expensive steam is required for good header pressure control, it is used. When properly tuned, the penalty for better header pressure control is usually not significant.

Hog Optimization

Hog optimization is incorporated in the boiler load allocation function. The operator enters a minimum and maximum hog rate limit. It is desired to keep the hog rate for each boiler at its maximum value as much as possible.

In a multi-fuel boiler, each fuel is treated as if it was a separate boiler by the boiler load allocator. The cost of hog ($/MMBtu) is entered as a very low value.

There is a significant lag time (several minutes) associated with the transport of hog from the hog bin to the boilers. This lag time prevents hog from being an effective swing fuel. However, an operator adjustable aggressiveness factor is used to allow hog to be treated as a pseudo swing fuel and maintain stable header pressure control.

Normally, hog flow will remain at the maximum limit (entered by the operator) and header pressure control is accomplished by adjusting gas flows. However, there are periods of low steam demand when hog flow must be reduced to prevent excess venting of steam to the atmosphere. When the fossil fuel is at minimum limits and further steam generation reduction is needed, the boiler allocator will reduce the hog flows of the power boiler. When the process demand increases, hog starts to increase. Hog is considered somewhat base loaded, since it always works its way back to the maximum limit.

Steam System Management

The next area of concentration is steam usage management. The primary focus is the proper allocation of the generated steam to satisfy steam header and system electric generation requirements. The steam system management components are described below.

Header Pressure Control Stability

One of the major challenges of implementing boiler load allocation is to maintain stable header pressure control for all combinations of boilers, fuels and equipment conditions. Boilers have different response times. Variable fuel quality and moisture content can effect the boiler's response time. Mechanical problems can limit the rate of load changes for a boiler.

Multi-fuel boilers, where hog is burned on a traveling grate, seem to create problems. Wet hog, long lag times in the hog feed system and hog piling on the grates can make using the boiler for header pressure control quite challenging.

An aggressiveness factor is assigned to each boiler fuel. It determines how much a boiler fuel is asked to participate in header pressure control. The factor varies from zero to one. When set to zero, the fuel does not participate in header pressure control. It becomes base loaded. When set to one, the boiler fuel has full participation in header pressure control. For any value in between, there is partial participation. Matching the aggressiveness factor to the responsiveness of each boiler is important for achieving stable header pressure control. Reducing the participation of boiler fuels that have poor steaming response is essential. However, there must be at least one boiler fuel (in large plants, preferably two) that has a fast steam response if satisfactory header pressure control is to be obtained.

Sometimes boiler constraints reduce header pressure control effectiveness. Each boiler's constraints are checked once per second to insure process limits are not being violated. As a boiler approaches a limit, its participation in header pressure control is reduced to zero. When some limits are exceeded, such as boiler steam generation, constraint controllers may make counter control moves to place the boiler back inside the safe operating envelope. Counter control moves are usually to the detriment of good header pressure control. This means that the header pressure is not the highest control priority. In fact, it is the lowest priority.

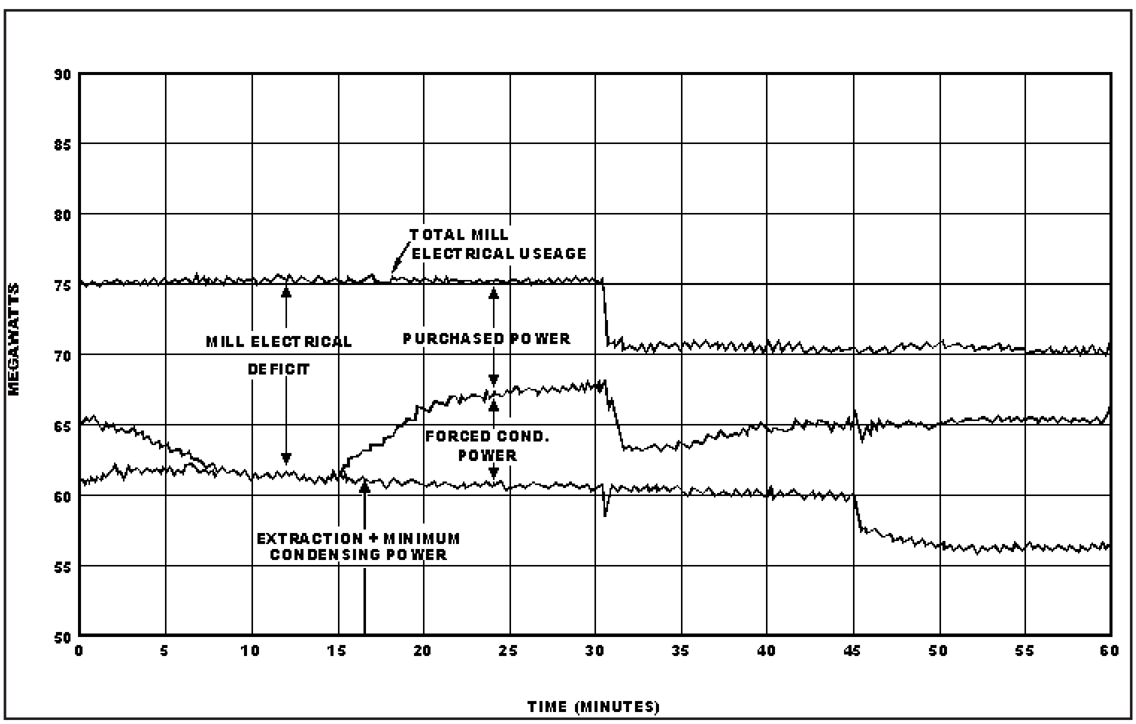
Turbine Lead Allocation

This subsystem provides supervisory control for 400, 150 and 50 psig extraction flows of all turbines to minimize PRV flows and maximize the total power that is generated. Turbines are assigned primary responsibilities to control various header pressures. Turbine extraction and exhaust flows are balanced by adjusting pressure setpoints. RTP tie-line power is adjusted by adjusting the load to the turbine condensers. When economical, additional power is generated by venting 50-psig steam by adjusting pressure setpoints.

A safe operating envelope for turbine load allocation has been defined that will:

1. Maintain all TG parameters (V1, V2, V3, MWs ... etc.) within the minimum and maximum limits.
2. Provide override control for 1,500 and 1,200 psig header pressures (outside of minimum and maximum limits).
3. Provide override control for 400-psig header pressure (outside of minimum and maximum limits).

Figure 7: Electrical Deficit



4. Provide override control for 150-psig header pressure (outside of minimum and maximum limits).
5. Provide override control for 80-psig header pressure (outside of minimum and maximum limits).
6. Provide override control for 50-psig header pressure (outside of minimum and maximum limits).
7. Maintain extraction flows on TG in control range for extraction pressure control.
8. Maintain sufficient swing range for TG's condensing flow to accommodate RTP tie-line control.

EMS adjusts turbine pressure setpoints and condensing load controls to achieve optimum turbine load balancing. Setpoints are "bumped" up or down until constraints are reached.

Electric Utility Rate Schedules

Most industrial customers purchase power from an electric utility company on a 15 or 30 minute interval. This type of rate schedule has a demand component and fixed energy charges for on and off-peak periods. The demand charge is usually based on the highest (peak) interval demand in the last 11 or 12 months. Interval demand is the average purchased power over an interval. Exceeding a previously set peak demand may cost hundreds of thousands of dollars since this new peak demand is usually ratcheted as the minimum demand charge for the following 12 months.

Real Time Pricing (RTP) is a new type of rate schedule offered to industrial customers by many electric utilities. The utility provides tomorrow's hourly prices based on the grid load and generating capability. Under the RTP rate schedule there is no demand charge or demand interval. Instead, the price of electricity varies on an hourly basis. Customers can purchase all of the power they need without worrying about setting a new peak demand. During summer periods, when the power demand becomes high, the midday hourly price is usually quite expensive. On some days it may even exceed $1,000/megawatt hour. The customer obviously doesn't want to buy any more of this expensive electricity than is absolutely necessary.

RTP Tie-Line Control

The ability to select the most attractive electric rate schedule is critical for today's energy manager. In this application the Tie line control has three modes:
1. RTP
2. Demand MW
3. Constant Purchase MW.

However, it is the RTP mode that is becoming more important in the deregulated business environment. In some instances the utility faces utility generation or transmission constraints and will provide attractive economic incentives for excess power generation or demand side management during peak periods. The objective is to reduce the mill electric demand or at some mills, generate power onto the grid during periods of high utility demand. This becomes a "Win-Win" for both the plant and the utility. The primary control objective for the mill is to adjust TG's steam flow to the condenser or vent to minimize the cost of providing the mill electrical deficit while staying within a predefined safe operating envelope.

Mill Electrical Deficit

To implement an RTP or Demand tie line controller, it is necessary to focus on the Mill Electrical Deficit shown in Figure 7. The electrical deficit is defined as the mill's total electrical power demand minus the power being generated due to the turbine's extraction flows and minimum flow to the condenser.

There are three sources of power that can be used to meet the deficit:

1. Purchased power
2. Forced condensing power
3. Venting (50-psig steam) power

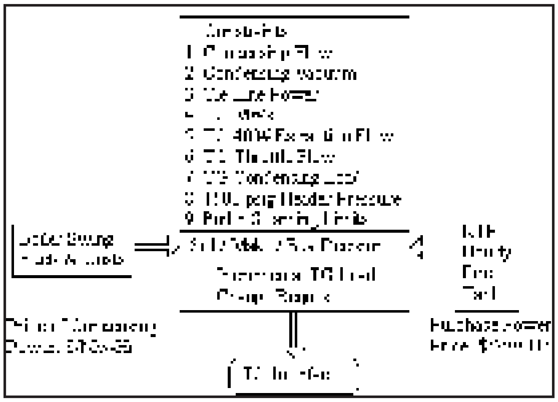
The function of the RTP control algorithm uses the mill electrical deficit to select the proper operating mode and to minimize utility cost.

RTP Control Algorithm

A schematic of the RTP tie-line control algorithm is shown in Figure 8.

The prioritized constraints are shown in the top part. They define the safe operating envelope. Using this constraint boundary, the turbine is "herded" to stay within the envelope while the tie-line control function is performed. It does not allow condensing to increase when:

Figure 8: RTP Algorithm



1. Condensing flow is high.
2. Condenser vacuum is low.
3. Purchase power is at low limit.
4. TG generated MWs is too high.
5. TG 400-psig extraction flow is too high.
6. TG condensing flow is maximized
7. TG throttle flow is high.
8. Total power boiler steam generation is very high.
9. 1,500-psig header pressure is very low.

It does not allow condensing to decrease when:

1. Condensing flow is at minimum.
2. Purchased power is at a high limit.
3. TG generated MWs is too low.
4. TG 400-psig extraction flow is too low.
5. TG condensing flow is too low.
6. TG throttle flow is too low.
7. Swing PB steam generation is very low.
8. 1,500-psig header pressure is very high.

RTP Rate Schedules

Each day the utility provides tomorrow's hourly prices by electronic mail or Internet to each RTP customer. Around 5:00 p.m. each day, tie-line control automatically downloads these prices (see Figure 9). At midnight, prices are automatically transferred to EMS for cost calculations.

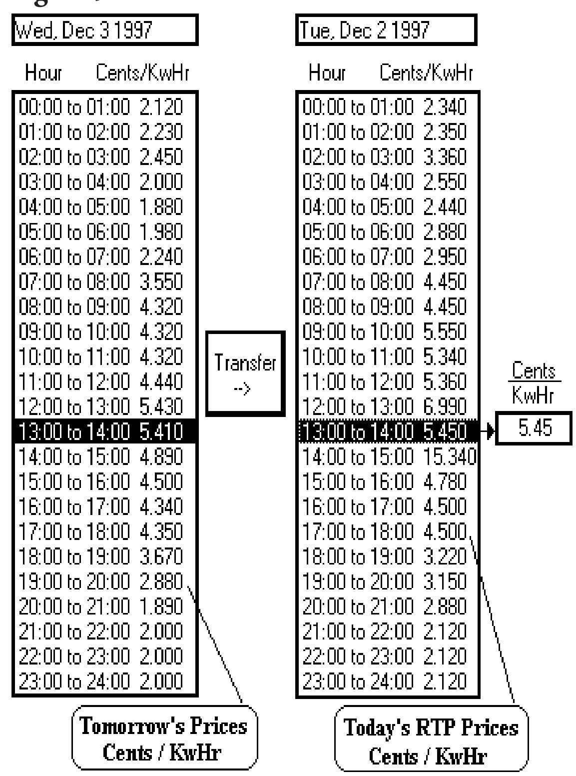
The control system continuously calculates the incremental cost to generate the next megawatt hour by forced condensing. Cost is based on the incremental cost of steam generation and the quantity of steam to generate another megawatt with forced condensing. The price of condensing power is compared to the cost of purchased power. When it is less expensive to buy power, EMS decreases turbine condensing until a process constraint is encountered.

When it is less expensive to make power, EMS increases condensing until a process constraint is encountered. When the cost to buy versus generate is nearly the same, condensing is controlled to minimize consumption of fossil fuel by the power boilers. The control adjusts the turbine's load to minimize electrical costs only when all variables are within the safe operating envelope. The control sacrifices minimum cost for safe process performance.

Additional Benefits

Operations worked closely with engineering in the development of the EMS operator interfaces. Diagnostic messages are presented in plain English language. The resulting control system is very easy to understand, diagnose, tune and modify.

Figure 9: Downloaded RTP Rate Schedules



A reporting feature identifies process bottlenecks based on frequency distribution of encountered constraints. Two characteristics of the EMS provide this ability:

1. The process units are always operating on the edge of the optimizing envelope.
2. Encountered process constraints are highlighted on the operating displays as the process moves between optimal operating points.

Operations can identify both magnitude and frequency of operating constraints and production bottlenecks.

Conclusions

The rule-based EMS described in this paper has been customized and implemented in several powerhouses. All projects have demonstrated substantial savings. The savings attributed to this powerhouse was a minimum reduction in gas purchase of 14 percent and a total reduction in purchased energy of 13 percent while improving steam and electric generation quality and reliability.

The design is based on fuzzy logic controls. A new inference engine and defuzzification method is employed. It is the heart of this new supervisory software package. This methodology integrates online optimization and a set of prioritized constraints. A list of process, equipment and environmental constraints is converted to a set of linguistic variables (fuzzy variables), which are used to define a safe operating envelope. When the process is operating inside the envelope, the EMS optimizes the powerhouse to provide process steam and electrical power at the lowest cost possible. The EMS usually operates the process on the boundary of multiple constraints.

This new control technology is applicable for many other online process optimizations in pulp and paper mills and other industrial facilities. Many proven applications include lime kiln optimization, CO and waste gas management in petrochemical complexes, multiple gas turbines, steam generation dispatch in large utilities and mining operations.

Acknowledgement

The insights and efforts of Dr. Frederick Thomasson are greatly appreciated in development of the original "Rule-Based Energy Management System."

References

1. Thomasson, F.Y. , 1979 Proceedings of the American Power Conference, American Power Conference, Chicago. P. 853.
2. Thomasson, F.Y. , Rule-Based Energy Management System, 2000 IETC

An Introduction to Steam Outsourcing

Tom Henry, Armstrong Service Inc.

One evolving trend in the boiler replacement business is the movement to outsource the equipment, installation, and operation and maintenance—called the build, own, operate, and maintain (BOOM) market.

Increasingly, companies no longer desire to allocate capital to "non-core" assets. Since most corporations define utilities as "non-core," the BOOM market is "booming" in certain sectors–particularly in large corporations with multi-plant operations (and colleges and universities).

What is beginning to emerge, especially among Fortune 500 companies, is that utility and operational people are realizing that capital will not be allocated for a boiler replacement despite being beyond its useful life. These people are being urged by CEO's and CFO's to find solutions elsewhere.

As a result, energy service companies (ESCOs) and lending institutions are developing services that satisfy the requirements of these companies. This is building awareness and momentum for utility asset outsourcing agreements.

Further, as companies continue to reduce staff, many of the people they have let go are those who have the know-how and experience to efficiently run steam plants. This further motivates management to seek outside expertise who can effectively manage and operate a steam system.

Environmental concerns are driving this trend as well. Those with coal systems are often concerned about the changing emission standards and regulations in the near term. This creates another driver to outsource this responsibility to an ESCO. The regulatory uncertainty and the continual capital required to keep in compliance can be draining. With BOOM, companies can avoid this distraction and accurately budget their steam energy expenses.

In a typical BOOM contract, the service provider is responsible for the design, engineering, procurement, construction, financing, and operation and maintenance of the entire system. Ownership of the installed equipment does not necessarily transfer to the client at the end of the term. However, the client user can purchase the system when the BOOM contract expires.

The client user pays the provider for the services by paying for the steam supplied from the ESCO's boiler. In fact, with the structure of some arrangements, the steam costs can be lower then what the user was incurring before the ESCO arrived.

This can make BOOM arrangements very appealing. Certain ESCOs can provide capital for new boilers, design and install them, and own, operate, and maintain them for steam costs less than what the facility was originally incurring. Additionally, the site now has on-site experts, with an entire organization behind them, to provide services that will drive down energy costs by constantly discovering and implementing energy efficiency projects.

While strong economics is the main motivator for entering into a BOOM contract, there are some other factors beyond capital avoidance and lack of experience and manpower pushing these agreements. For example, a company desires to mothball an existing steam plant because of systemic inefficiency of the generating assets. It can make better economic sense to outsource the entire ownership of the steam plant including the O&M. Similarly, a company may be having trouble controlling energy costs. Management has grown impatient watching the steady increase in total utility operating costs and desire to reduce or control these costs by turning over the responsibility and risk to an ESCO.

Other factors include:

- Utility-supplied steam is no longer available.
- Due to market fluctuations, an existing cogeneration plant becomes inefficient.
- Utility rates are high.
- Lack of system reliability is a growing concern.

Case in point:

A Fortune 500 food processing facility, which manufactures 5,000 products sold in 200 countries, was exploring utility cost reduction options for its Midwest facility because its boilers were aged.

At this facility, it produces gravies, ketchup, sauces and soups. The facility has total annual combined utility costs of more than $4 million. The plant's thermal demand is 340 million pounds of steam per year and it has an electric power demand of 19.1 million kW per year.

The $9 billion per year corporation opted for a BOOM contract for its Midwest facility, selling the powerhouse assets to a technology based ESCO. The contract stipulates that the ESCO owns and operates the facility for 16 years in an agreement valued in excess of $64 million.

The ESCO installed two new 2,800 horsepower watertube steam boilers as the primary source for thermal energy requirements. The ESCO also installed a new air compressor and sequencing control package to manage the 718,000 thousand cubic feet annual demand.

The ESCO performed turnkey design and implementation of steam, compressed air, electric, and wastewater projects to increase utility efficiency and generate energy cost savings at the plant. Further, as part of its ownership responsibility, it provides a continual sustaining engineering service to ensure continued benefits of the implemented projects.

The ESCO agreement structure affords this company numerous benefits:

- It received an up-front capital payment for its powerhouse assets.
- The overall utility cost has been reduced at this facility.
- No capital from the company was required to produce savings.
- The ESCO will aggressively pursue utility and project savings opportunities throughout the term of this agreement.
- Operations and maintenance risk have been transferred to the ESCO.
- The company is billed for all utility services on a variable basis correlated to product produced.
- The ESCO reviews and pays all utility bills.
- Utility systems are continuously being upgraded and improved to achieve “Best in Class” condition.

Therefore, in reviewing how this ESCO installed this new boiler for this food processing facility, one can see that the customer received a substantial cash payment, avoided having to provide millions of the company’s own capital for upgrades, and had its overall utility expenses reduced. If the food processor chose the conventional method, it would have millions less in capital available to grow their business.

If boiler upgrade/replacement is needed, a facility owner/manager should not hesitate to determine if this new trend in boiler replacements could be economically attractive at the facility.

About the Office of Energy Efficiency and Renewable Energy

A STRONG ENERGY PORTFOLIO FOR A STRONG AMERICA

Energy efficiency and clean, renewable energy will mean a stronger economy, a cleaner environment, and greater energy independence for America. By investing in technology breakthroughs today, our nation can look forward to a more resilient economy and secure future.

Far-reaching technology changes will be essential to America's energy future. Working with a wide array of state, community, industry, and university partners, the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy invests in a diverse portfolio of energy technologies that will:

- Conserve energy in the residential, commercial, industrial, government, and transportation sectors
- Increase and diversify energy supply, with a focus on renewable domestic sources
- Upgrade our national energy infrastructure
- Facilitate the emergence of hydrogen technologies as a vital new "energy carrier."

The Opportunities

Biomass Program
Using domestic, plant-derived resources to meet our fuel, power, and chemical needs

Building Technologies Program
Homes, schools, and businesses that use less energy, cost less to operate, and ultimately, generate as much power as they use

Distributed Energy & Electric Reliability Program
A more reliable energy infrastructure and reduced need for new power plants

Federal Energy Management Program
Leading by example, saving energy and taxpayer dollars in federal facilities

FreedomCAR & Vehicle Technologies Program
Less dependence on foreign oil, and eventual transition to an emissions-free, petroleum-free vehicle

Geothermal Technologies Program
Tapping the earth's energy to meet our heat and power needs

Hydrogen, Fuel Cells & Infrastructure Technologies Program
Paving the way toward a hydrogen economy and net-zero carbon energy future

Industrial Technologies Program
Boosting the productivity and competitiveness of U.S. industry through improvements in energy and environmental performance

Solar Energy Technology Program
Utilizing the sun's natural energy to generate electricity and provide water and space heating

Weatherization & Intergovernmental Program
Accelerating the use of today's best energy-efficient and renewable technologies in homes, communities, and businesses

Wind & Hydropower Technologies Program
Harnessing America's abundant natural resources for clean power generation

To learn more, visit ***www.eere.energy.gov***

For additional information on BestPractices Steam, contact:

Fred Hart
Industrial Technologies Program
U.S. Department of Energy
1000 Independence Avenue, N.W.
Washington, DC 20585
(202) 586-1496

Kristin Lohfeld
Industrial Program Manager
Alliance to Save Energy
1200 18th Street, N.W. Suite 900
Washington, DC 20036
(202) 530-4349

To order additional copies of this publication please call:

Industrial Technologies Program Information Clearinghouse at (800) 862-2086 or visit www.eere.energy.gov/industry

Industrial Technologies Program
Energy Efficiency and
Renewable Energy
U.S. Department of Energy
Washington, D.C. 20585

DOE/GO-102003-1805
November 2003